FOSSIL ENERGY

DOE/BC/14958-15
(DE96001264)

GREEN RIVER FORMATION WATER FLOOD DEMONSTRATION PROJECT

Final Report

By
Bill I. Pennington, Inland Resources, Inc./Lomax Exploration Co.
John E. Dyer, Inland Resources, Inc./Lomax Exploration Co.
John D. Lomax, Inland Resources, Inc./Lomax Exploration Co.
Milind D. Deo, Dept. of Chem. and Fuels Eng., Univ. of Utah

November, 1996

Performed Under Contract No. DE-FC22-94BC14958

Inland Resources Inc./Lomax Exploration Company
University of Utah

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615) 576-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield VA 22161

DOE/BC/14958-15
Distribution Category UC-122

Green River Formation
Water Flood Demonstration Project

Final Report

By
Bill I. Pennington, Inland Resources, Inc./Lomax Exploration Co.
John E. Dyer, Inland Resources, Inc./Lomax Exploration Co.
John D. Lomax, Inland Resources, Inc./Lomax Exploration Co.
Milind D. Deo, Dept. of Chemical & Fuels Engineering, University of Utah

November 1996

Work Performed Under Contract No. DE-FC22-94BC14989

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Edith Allison, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by:
Inland Resources, Inc./Lomax Exploration Co.
And
University of Utah

TABLE OF CONTENTS

LIST OF TABLES

List of Figures

Abstract

The objectives of the project were to understand the oil production mechanisms in the Monument Butte unit via reservoir characterization and reservoir simulations and to transfer the water flooding technology to similar units in the vicinity, particularly the Travis and the Boundary units. Comprehensive reservoir characterization and reservoir simulations of the Monument Butte, Travis and Boundary units were presented in the two published project yearly reports. The primary and the secondary production from the Monument Butte unit were typical of oil production from an undersaturated oil reservoir close to its bubble point. The water flood in the smaller Travis unit appeared affected by natural and possibly by large interconnecting hydraulic fractures. Water flooding the boundary unit was considered more complicated due to the presence of an oil water contact in one of the wells.

The reservoir characterization activity in the project basically consisted of extraction and analysis of a full diameter core, Formation Micro Imaging (FMI) logs from several wells and Magnetic Resonance Imaging (MRI) logs from two wells. In addition, several side-wall cores were drilled and analyzed, oil samples from a number of wells were physically and chemically characterized (using high-temperature gas chromatography), oil-water relative permeabilities were measured and pour points and cloud points of a few oil samples were determined. The reservoir modeling activity comprised of reservoir simulation of all the three units at different scales and near well-bore modeling of the wax precipitation effects.

Core analyses and examination of the results of the FMI logs were the principle tools utilized for the geologic characterization of the unit. Oil production from most units in the region is from multiple, largely distinct sand bodies. The geologic study identified the Lower Douglas Creek reservoir (which contributed to most of the production in the Travis unit) to form isolated lenses that can reach over 100 feet of net thickness. Localized nature of this reservoir combined with lithologic heterogeneity and complex architecture makes this a difficult water-flood candidate. The D1 reservoir on the other hand, which contributed to over 2/3rd of the production in Monument Butte, is laterally continuous and lithologically homogeneous.

The reservoir characterization efforts identified new reservoirs in the Travis and the Boundary units. The reservoir simulation activities established the extent of pressurization of the sections of the reservoirs in the immediate vicinity of the Monument Butte unit. This resulted in a major expansion of the unit and the production from this expanded unit increased from about 300 barrels per day to about 2000 barrels per day.

The technology transfer component of the project was very successful. Ten technical papers and presentations resulted as a direct consequence of this project. Several new water floods were begun in the Greater Monument Butte region, modeled essentially after the Lomax/Inland Monument Butte flood.

Executive Summary

Despite successful water floods in nearby Wonsits Valley, Walker Hollow and Red Wash fields, secondary recovery via water flooding in the Monument Butte unit was assessed to be technically unfeasible. The fluvial deltaic geologic environment, low permeabilities of sands and waxy nature of the crude were some of the attributes that contributed to this preliminary assessment. The reservoirs in this region are undersaturated with the initial reservoir pressure close to the initial bubble point pressure resulting in a primary recovery of only about 5%. Thus, for the economic viability of any field in the region, some form of secondary recovery is a necessity. Based on these considerations, water flood operations were begun in Monument Butte. Contrary to initial expectations, the flood was quite successful and the production rate from the unit increased almost by an order of magnitude. The objective of this project was to learn about the Monument Butte flood and transfer the technology to other units/fields in the region in general and to the Travis and the Boundary units in particular.

The project essentially had three central activities.

- Drilling new wells to identify the expanse of each of the units.
- Performing detailed reservoir characterization using conventional and modern logging methods. Characterization also included fluid composition measurements, porosity-permeability measurements and determination of oil-water relative permeabilities.
- Understanding the reservoir performance using reservoir simulation.

Understanding of the performance of the Monument Butte water flood contributed toward a fast-paced unit expansion. More than 30 additional wells were drilled (by Lomax Exploration Company/Inland Resources Inc.) and production from the expanded unit has increased almost by an order of magnitude since the project began. The reservoir performance, both in the primary

and secondary phases was determined to be typical of an undersaturated oil reservoir. Simulations revealed that almost 30% of the injected water had migrated outside the boundaries of the unit. This had led to the pressurization of the outlying areas. Additional drilling and good responses from most wells corroborated this hypothesis. The Formation Microimaging Logs (FMI) and the Magnetic Resonance Imaging Logs helped identify thin pay zones saturated with hydrocarbons. The reservoir was modeled at various scales and images generated at different times were animated to create a video movie.

The FMI log in one of the wells in the Travis unit helped identify new reservoir horizons and oil was produced from these intervals in the primary mode. The water flood in the Travis unit was hampered by the presence of large natural fracture systems which may have intersected the hydraulic fractures to create to high permeability conduit for water. Well spacing of only 20 acres may have exacerbated this problem. Whether water flood will ultimately be successful in this unit remains to be seen.

The primary production in the Boundary unit was also expanded. A 28-layer reservoir model was used to match the primary performance of the unit. Oil-water contact in one of the wells complicated the modeling process. The model revealed that hydraulic fracturing needs to be undertaken with care since there is a chance that the fracture may intersect the underlying aquifer. At the time of this writing, the C-sand interval in Boundary was being water flooded. Considering the expanse of the reservoir, the chances of a successful water flood in Boundary are fairly good.

A near well-bore analysis of the water injection process into a reservoir containing waxy crude was performed. A thermodynamic model was used to match the pour point of the Monument Butte crude oil. An analytical model used to study the effect of injection on wax precipitation and oil recovery revealed that near well-bore wax precipitation was likely and that this would lower the ultimate recovery by about 5%. It was also determined that this effect would be felt late in the life of the flood.

Several new water floods were begun in the Greater Monument Region directly as a result of this project. Most of the technical papers and reports resulting from the project found wide circulation.

Thus, the success of the Monument Butte unit water flood could be attributed to:

- Lateral continuity of the D1 and the B2 sand bodies.
- Use of the best producers as injectors to get the reservoir pressurized quickly.
- Use of fresh water to maintain reservoir fluid compatibility
- Well designed hydraulic fracturing to provide enhanced injectivity and producibility.

The geologic characterization revealed that some of the sand bodies were not amenable to water flooding due to their lithologic complexity. The measured PVT properties showed that the initial reservoir pressure was close to the initial bubble point pressure. These measurements provided an accurate initial oil formation volume factor for oil in place computations. The fluid-rock properties measurements showed that the relative permeability to water at residual oil saturation was very low (between 0.07 and 0.1) and declined rapidly as the oil saturation increased. This explained, to a certain extent, the low water cuts in the Monument Butte water flood at a fairly mature stage.

The project was a demonstration of well-designed water flood technology. The methods and techniques employed in the project will be applicable to a large area (about 300 square miles) in the Greater Monument Butte Region.

Chapter 1. Introduction

In April, 1981, a discovery well, the Federal #1-35, was drilled in the Monument Butte field in Utah (Fig. 3-1) and completed in the Douglas Creek Member of the Green River Formation. Development proceeded on 40-acre spacing, concentrating principally on the "D" Sandstone (Lomax terminology). Primary production was anticipated to recover 309,000 STB of oil, or 5.5% of the 5.67 million STB of the oil in place. Using primary methods, field production declined to 45 bbl/day. In order to improve the recovery of oil from this reservoir, Lomax Exploration Co. initiated a water flood. There was some historical precedence for this type of secondary recovery project in the Wonsits Valley field in the eastern part of the Uinta Basin. However, the technique had never been attempted in the vicinity of the Monument Butte field. Some reservoir engineering studies had predicted the procedure would not be successful based upon reservoir heterogeneity, the high paraffin content of the crude oil, and the low energy of the reservoir.

In 1987, Lomax Exploration Company formed a secondary recovery unit in order to initiate a water flood. Primary production had declined to 30 bbls/day as the flood was initiated. The flood proved successful and, as of November, 1991, production at Monument Butte had increased to 330 bbls/day. As a result of this water flood, estimated ultimate recoverable reserves of the "D" sandstone reservoir alone have increased from 300,000 bbls to over 1.2 million bbls, and recovery has increased from 5% to an estimated 20% of the oil in place. The water flood has since then expanded to include other sandstone reservoirs in the lower portion of the Green River Formation.

The three primary units which were the targets of this study (Monument Butte, Travis and Boundary) are all located in east-central Utah in Duchesne county. Details of the unit, unit maps, etc. were presented in the two earlier yearly reports (U.S. DOE, 1994; U.S. DOE, 1995). The early drilling activity in the region is summarized in the following paragraphs.

Review of Early Drilling and Productionfrom 1952 through 1996

In Townships 8 & 9 South, Ranges 15, 16, & 17 East, of Duchesne County, Utah; twenty five wells were completed for production during the period of 1952 through 1980. As of 01\01\84, the first annual and monthly production records reported by Dwight's, the cumulative production from the twenty five wells was 870,098 BBLS oil, and 566,635 MCF gas. Through 1983 these wells averaged cumulative production of 34,804 BBLS oil. During 1984 an average of fourteen wells were still producing, and total production for 1984 was 20,148 BBLS oil, and 52,432 MCF gas, the wells each were averaging approximately 4 BOPD. As of 12/31/1995 there were still ten wells producing, and the cumulative production for the twenty five wells was 1,076,688 BBLS oil, for an average of 41,187 BBLS per well over a forty three year period.

The high oil prices of the early eighties triggered new activity in the area, the following table indicates the completion activity since 01/01/1980:

Year	Completed wells	Comments
1980	3	
1981	18	activity created by high oil prices.
1982	46	continued development under high oil prices.
1983	34	
1984	20	Activity slowing down due to lower oil prices.

1985	13	Operators concerned about high decline rates.
1986	3	Operators concerned about reserve recovery.
1987	3	Primary recovery of the oil in place averaged less than 5%. Lomax pilot water flood started in November on the Monument Butte Unit.
1988		Decline arrested, production increased from 35 to 80 BOPD.
1989	4	Water flood production increased from 80 to 200 BOPD.
1990	12	Eleven well field development offsetting MBU by a minority partner in the Unit. MBU production increased to300 BPOD.
1991	3	In August Lomax formed the Travis Unit for its second water flood attempt.
1992	4	In July Lomax formed the Boundary Unit, and in October the Department of Energy-sponsored water flood test program, a three year field test on three secondary recovery units was approved.
1993	27	On the basis of the continuing success of the Monument Butte Unit, other operators started to develop water flood projects, and increased development drilling associated with water flood projects.

1994	34	Increased water flood activity, and development wells drilled to define new water flood projects.
1995	47	Extending water floods, and development wells defining new water flood areas.
1996	112*	Based on personal communication with active operators in the area under discussion. Forty five wells have been drilled so far this year and at least three rigs are currently running.

Summary of Yearly Reports

As part of this project, two yearly reports were published (U.S. DOE , 1994; U.S. DOE, 1995).

Summary of Yearly Report 1

At the start of the project, Monument Butte unit was the most developed of the three units and currently had 22 wells, eight injectors and the rest producers. The unit contained about 9 MMstb of original oil in place (OOIP) primarily in two zones, the D and the B. About 4.5% of the OOIP had been recovered by primary production, when the water flood was initiated in late 1987. Two wells were drilled in Monument Butte, 10-34 and 9-34. Well 10-34 drilled in late 1992, did not appear to be affected by the water flood. The production from 10-34 resembled production from a well producing from a partially depleted undersaturated reservoir. Well 9-34 drilled in late 1993 penetrated producing sands and appeared to be producing from zones which were pressurized by the water flood. The production performances for these two wells were logical considering the distances of these wells from injection wells, 5-35 and 13-35.

Formation Micro-Imaging (FMI) logs were obtained for these wells for better geologic understanding. Logs and stratigraphic sections from several wells were analyzed and a geologic model of the reservoir was constructed.

As part of the comprehensive engineering study of the unit, a general purpose core flooding, pressure-volume-temperature (PVT) system capable of measuring reservoir fluid properties was designed and built. Compositions of the Monument Butte oils were measured using a novel capillary chromatographic method. Most of the oils contained about 30% C_{11} + material. All the relevant reservoir fluid properties were measured. The geologic data and the reservoir fluid property data were integrated into a volumetric assessment and a detailed reservoir simulation study. The volumetric assessment was based on simple reservoir engineering calculations (zero-dimensional). Results from the simple volumetric study were found consistent with the comprehensive three-dimensional multiphase reservoir simulation study. The reservoir simulation study was successful in matching field history. The overall field production data was matched by the reservoir simulator within 10% and the individual well data were matched within 15%.

A thermal well bore model was developed to examine the temperature profiles in the well bore. The model showed that under the conditions of injection, injected water could be reaching the perforations at temperatures 50^0-70^0 F lower than the reservoir temperature. Due to the high paraffin contents of the reservoir fluids, the study concluded that there was a strong possibility of paraffin deposition in the vicinity of the well bore.

The Travis unit had produced about 245 Mstb of oil and 1.08 MMMscf of gas in primary production. Most of the production was from the Lower Douglas Creek (LDC) sand. Injection in well 15-28 at 1000 stb/d appeared to pressurize the reservoir. However, when well 14-28a was drilled in late 1992, injection in 15-28 had to be stopped due to water channeling in 14a-28. Producer 10-28, also had a water channeling problem. The new FMI logs in 14a-28 showed that LDC was extensively fractured. The fracture orientations were found to coincide with the channeling paths. The new logs in 14a-28 also revealed the existence of thin, but producible D sands. Based on this information, 14a-28 and also wells 14-28 and 10-28 were completed in the D-sand interval. The production from this zone was similar to production from an undersaturated reservoir close to the initial fluid bubble point (about 5% of OOIP recovery). Once the production from 14a-28 declined, it was converted to an injector, injecting about 300 stb/d into the D-sands. Well 15-28 was started back on injection at a slower rate of about 300 stb/d, and well 3-33 was converted to an injector, injecting about 300 stb/d into LDC. The surface pressure data showed that the reservoir was being gradually pressurized. The water flooding operations in Travis appear to be dominated by natural or created (hydraulic) fractures. An engineering study of the Travis unit, similar to the Monument Butte was conducted. The geologic data and reservoir fluid properties were integrated into a dual-porosity, dual-permeability fractured reservoir model. The model provided a good match with the primary production history and predicted increased oil production on water flooding. Well 10-20 drilled in the Boundary unit did not intersect producing sand layers. This illustrated the risks involved in operating in fluvial deltaic environments.

The results of one of the Monument Butte unit simulation studies resulted in a paper SPE 27749, which was presented at the Improved Oil Recovery Symposium in Tulsa, Oklahoma in April 1994. The success of the water flood in the Monument Butte field and an understanding of the underlying mechanisms as a result of this project, resulted in the initiation of two major water floods in the Uinta Basin by Equitable Resources Inc. and by Pacific Gas and Energy.

Summary of Yearly Report 2

Lomax Exploration Company became a fully owned subsidiary of Inland Resources Incorporated. The project was continued by the new management team in partnership with the University of Utah (Earth Sciences Resources Institute and the Department of Chemical and Fuels Engineering).

All of the new wells drilled in the Monument Butte unit (10-34, 9-34 and 7-34) were reasonably successful. At the end of May 1996, well 10-34 had a cumulative oil production of 27,197 bbls. Cumulative production for wells 9-34 and 7-34 were 18,387 bbls and 19,592 bbls respectively. That in itself demonstrated the viability of water flood and pressure maintenance in fluvial deltaic reservoirs which were barely undersaturated (whose initial bubble point pressure was close to the initial reservoir pressure). The production from the unit appeared limited due to water injection limitations. The reservoir modeling showed that about a third of the injected water was migrating beyond unit limits. The response to the water flood was also affected by injection into sands which did not have direct communication with other wells. Finally, hydraulic fracturing also appeared to have played a role in determining the response of some of the wells. By December 31, 1994, the water flood had already produced 142% of the primary production and 34% of the gas production. A cumulative gas oil ratio of about 940 scf/stb in comparison to the initial GOR of about 500 scf/stb shows that oil is still being produced from zones which are above the current bubble point and from zones which have free gas.

Continued water injection in the Lower Douglas Creek (LDC) sand pressurized this reservoir in the Travis unit. Surface pressures of nearly 2000 psia were reached in the two injectors, 15-28 and 3-33, indicating bottom hole pressures of about 4600 psia. Communication problems between the injectors and producers (2-33 and 10-28) appeared to have caused the slow response to the water flood being observed in this unit. The well 5-33 drilled in the unit did not intersect the LDC sandstone. However, the well was completed in other sands.

New production and injection wells were planned for the Boundary unit. There was no field activity in the unit in 1994.

Detailed geologic and reservoir characterization of all the three units was continued. The FMI logs showed the fine structures in the sand bodies. Careful analysis and interpretation of these logs revealed detailed fracture information. The fractures were found oriented mostly in the east-west direction. A comprehensive core description of the core from well 14a-28 was also completed.

The reservoir simulation and modeling of all the three units was also continued. The Travis unit was modeled using three alternative models; a homogeneous model with locally adjusted permeabilities, a fractured model (dual-porosity, dual permeability) and a hydraulically fractured model. All of the three models were tuned to match the primary production data from the unit and were then used to predict the water flood response. All the three models predicted that a response to the water flood should have been observed in well 2-33 had the sands been in good communication. The model predictions were slightly different in terms of production rates and water oil ratios.

From the experience gained in modeling the Monument Butte and the Travis units, a comprehensive reservoir model of the Boundary unit was constructed. Data at 2 foot resolution was incorporated in the model. The model had 15 oil bearing layers separated by 13 non oil bearing layers for a total of 28 layers. The water-oil contact in one of the wells and the fact that the extent of the aquifer was not established, made this model the most complex of the three reservoir models. The model oil and gas predictions matched the field results reasonably well. The logs for well 13-21, the largest producer in this unit did not show a water-oil contact. But the oil production from well 13-21 and the slow decline from that well could not be explained on the basis of sands present in that well. Hence it was determined that the production from 13-21 was aided by water influx from the same aquifer which was seen in the logs of well 7-20. It was also determined that 13-21 communicated with this aquifer through its hydraulic fracture.

It was shown in the last yearly report that the crude oils from these reservoirs are extremely waxy with cloud points of about 120^0 F. Determining the conditions under which wax precipitation occurs and finding the effect of this precipitation on oil recovery were important tasks in this project. It was also shown that the injected water reaches the perforations at temperatures much lower than the formation temperatures. The thermodynamic aspects of these oils and wax formation at these temperatures as analyzed in this report and it was shown that wax precipitation models could be simplified to give equivalent results. It was also shown that wax appearance data as well as wax and oil composition data would be required to tune these models.

A first-generation model based on the generalized method of characteristics was developed. This model showed that wax precipitation causes lower oil recoveries and that the effect of precipitation is felt only in the later part of the water flood. For the parameters chosen in this study, the recovery reduction was nominal (4%), but for a certain combinations of parameters, the reduction in oil recovery could be as high as 10%.

The technology transfer aspect of the project was continued actively with presentation in the SPE-DOE Improved Oil Recovery Symposium in Tulsa, poster sessions at the AAPG meeting in Denver and the SPE Annual Fall Meeting in New Orleans, and a presentation at the International Oilfield Chemistry Symposium in San Antonio.

Current Reporting Period

The expansion of the Monument Butte unit on the west, north-east and on the east portions of the unit continued at a fast pace. A total of 30 wells were drilled either in the unit or in the expansion areas. Reservoir characterization continued with emphasis on gaining understanding regarding the expanse of each of the reservoir units. Reservoir modeling was also performed on areas much larger than the individual units. In this final report, expansion of the Monument Butte unit is summarized along with new production results. Detailed geologic and stratigraphic interpretation is presented next. Geostatistical modeling and large-scale reservoir simulations are the subject of the next chapter. An economic analysis, and project summary and conclusions complete this final report.

References

U. S. DOE 1994, Green River Formation Water Flood Demonstration Project, DE-FC22-93BC14958, Yearly Report, 1994.

U. S. DOE 1995, Green River Formation Water Flood Demonstration Project, DE-FC22-93BC14958, Yearly Report, 1995.

Chapter 2. Production Report

Wells drilled as part of this project are summarized in Table 2-1. Production from the new wells drilled, the expansion wells and unit productions are summarized in Table 2-2. The Monument Butte unit has produced more than twice the oil produced during primary. The expansion units have also performed remarkably well. The sections involved in the unit expansion are shown in Figure 2-1. The wells in close proximity of the original flood, as expected, have responded most favorably with lower overall gas oil ratios. Most of the new wells drilled in Boundary have been successful. In Travis, the Lower Douglas Creek water flood is still a question mark. However, about 60,000 barrels of oil has been produced from newly identified reservoirs in Travis.

Table 2-1. New wells drilled as part of this project

Unit	Well	Date Drilled	Advanced Logs
Monument Butte	10-34	10/92	FMI, MRIL
Travis	14a-28	10/92	FMI
Boundary	10-20	4/93	None
Monument Butte	9-34	11/93	FMI, MRIL
Monument Butte	7-34	11/94	FMI, MRIL
Travis	5-33	10/94	FMI
Boundary	12-21		FMI

Table 2-2. Production from the new project wells in the Monument Butte unit as of 5/31/96

Well Number	Date on line	Oil Produced (Barrels)	Gas Produced (MCF)
10-34	11/26/92	17,330	27,197
9-34	01/09/94	22,566	18,387
7-34	12/24/94	13,668	19,592
2A-35	04/18/95	17,923	6,295
Unit	-	1,135,078	2,263,102

Table 2-3. Production from some of the new wells in the Monument Butte northeast expansion as of 5/31/96

Well Number	Date on line	Oil Produced (Barrels)	Gas Produced (MCF)
11-25	1995	18,388	21,579
12-25	1995	3,989	10,045
13-25	08/22/95	10,712	17,449
14-25	10/14/95	15,181	41,037
16-26	10/28/95	14,093	22,073

Table 2-4. Wells in the Monument Butte west expansion: Production as of 5/31/96

Well Number	Date on line	Oil Produced (Barrels)	Gas Produced (MCF)
3-34	1995	4,857	7,730
5-34	09/11/95	23,185	76,824
6-34	04/08/95	4,387	20,103

Table 2-5. Wells in the Monument Butte east expansion: Production as of 5/31/96

Well Number	Date on line	Oil Produced (Barrels)	Gas Produced (MCF)
3-36	10/28/95	4,038	7,528
10-36	10/16/95	26,470	29,883
14-36	06/20/95	20,558	39,725
15-36	10/14/95	6,437	3,996
16-36R	09/13/95	14,623	21,992

Table 2-6. Production from some of the new wells in the Monument Butte southeast expansion as of 5/31/96

Well Number	Date on line	Oil Produced (Barrels)	Gas Produced (MCF)
4-1	1995	2,582	4,337
5-1	1995	10,955	31,136
8-2	12/02/95	14,590	26,271

Table 2-7. Production from the Travis unit as of 5/31/96

Well Number	Date on line	Oil Produced (Barrels)	Gas Produced (MCF)
5-33	12/12/94	5,712	24,297
Unit	-	300,995	1,424,193

Table 2-8. Production from some of the new wells in the Boundary unit as of 5/31/96

Well Number	Date on line	Oil Produced (Barrels)	Gas Produced (MCF)
10-21	09/28/95	13,264	24,297
12-21	01/21/95	4,305	8,788
Unit	-	224,828	697,360

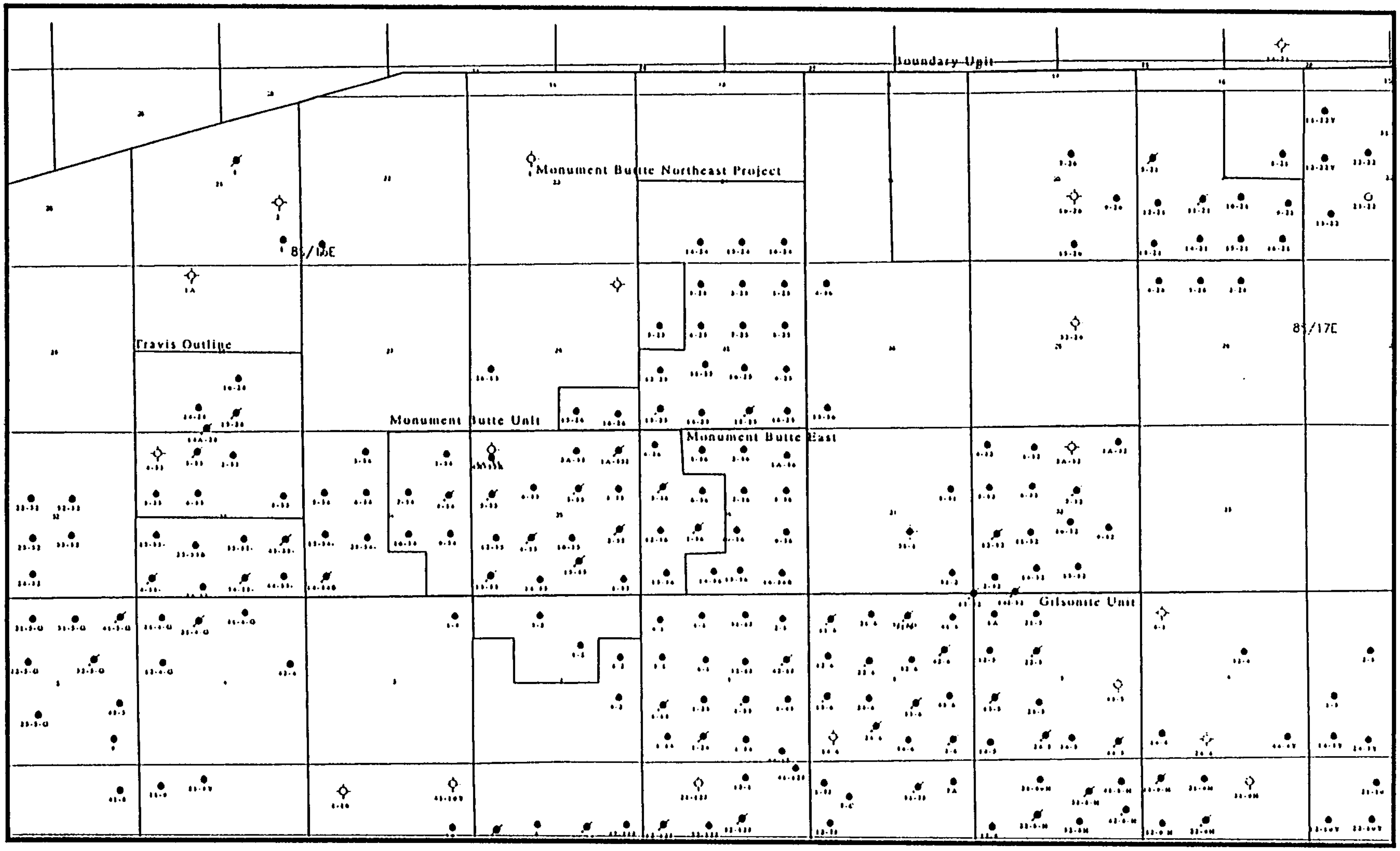


Figure 2-1. The three project units, Monument Butte, Travis and Boundary with updated well information.

Chapter 3. Stratigraphy and Image Log Interpretation

This project was initiated with the U. S. Department of Energy to improve the characterization of the sandstone reservoirs. Initially, the depositional origin of the reservoirs was poorly understood and all the sands were thought to be of fluvial origin. Correlation of sandstone bodies between adjacent wells was often difficult. And fracturing was not thought to play a significant role in reservoir heterogeneity in this part of the basin.

REGIONAL GEOLOGY

The Monument Butte oil field is located in the central portion of the Uinta Basin, Utah (Fig. 3-1). Reservoirs are principally developed in the Eocene Green River Formation. Recent summary articles present the level of understanding of the tectonic, climatic and sedimentological evolution of the basin (Fouch et al., 1992).

The structural development of the Uinta Basin started with the withdrawal of the Cretaceous inland sea and the beginning of the Laramide orogeny (Narr and Currie,1982). The late Cretaceous North Horn Formation is stratigraphically the lowest unit to reflect subsidence of the basin (Fouch, 1976). Within this basin, Lake Uinta formed and became the site for the deposition of both reservoir and source rocks in the Greater Monument Butte field. The uplift of the Uinta Mountains on the northern boundary of the lake provided a high relief source area. This uplift took place along high-angle reverse faults that trend in an east-west direction. At the southeastern boundary of the basin, the Uncompahgre uplift trends to the northwest (Fig. 3-2). Fractures parallel to this trend are present in the rocks of the Monument Butte area, and, on a regional basis, form the hosts for gilsonite veins. In general, fracture orientations will change within the basin and be related to the older structural trends in the vicinity. Narr and Currie show that regional joints follow north-south, northwest-southeast and northeast-southwest trends. The sedimentary rocks of the basin have undergone a single cycle of deposition, subsidence and uplift.

The Uinta Basin developed in an asymmetric fashion which has, in general, controlled the style of sedimentation. High-angle normal faults form the northern boundary adjacent to the Uinta Mountains. This resulted in a source area of relatively high relief and the deposition of a coarser-grained stratigraphic section. The southern portion of the basin was a zone of low relief and finer-grained sedimentary deposits. The half graben sedimentation style is similar to that observed in many modern (Cohen, 1990; Johnson et al., 1995) and ancient (Lambiase, 1990) lacustrine basins.

Oil and gas bearing strata of the Eocene Lower Green River Formation consist of fluvial-deltaic deposits. Sandstones were deposited along shorelines, in deltas, and in distributary and fluvial channels. Carbonates were deposited in marginal lacustrine environments. Along the southern and eastern margins of the Uinta Basin, fluvial-deltaic sediments of Eocene age represent over one-third of the total stratigraphic section. In the southern Uinta Basin, oil and gas reservoirs are concentrated along an east-west paleoshoreline trend that extends for a distance of about 60 miles. Within this zone, sandstones form fluvial-deltaic reservoirs. The southern, updip portion of the productive area is characterized by the transition from marginal lacustrine deposits into clayey lower delta plain facies. The northern boundary of the fairway is characterized by the transition from sandy shoreline deposits to fine-grained open lacustrine rocks. The open lacustrine facies consist of nonreservoir organic-rich mudstones and calcareous claystones. The fairway is present across portions of both Uintah and Duchesne counties, where it extends from the Greater Red Wash field westward to the Brundage Canyon field. The Greater Red Wash field, discovered in 1950, occcupies the easternmost portion of the fairway in which numerous marginal lacustrine sandstone and carbonate reservoirs have combined production of over 135 million STBO. The western portion of the fairway has undergone limited development and is characterized by small, localized oil fields.

Within the project area, there are two major structural trends observed on the surface, gilsonite veins and the Duchesne fault zone. The Duchesne fault zone (Fig. 3-1) is an east-west trending zone of surface fracturing and faulting (Ray et al., 1956). The zone has been traced for a total distance of 42 miles and has a width of up to 2 miles. The mapped fault zone is located to the north of the Monument Butte unit, approximately through Lomax's Boundary Unit. There is little information published on the character of this zone. Nielson et al. (1993) showed that fracturing associated with the Duchesne fault was prominent in the Duchesne oil field and had important controls on production of oil from that field.

Northwest trending gilsonite veins form another obvious structural element in the vicinity of Monument Butte (Fig. 3-1). The Pariette Mine produced gilsonite in the northeast corner of section 31, about 1.5 miles to the east of the Monument Butte Unit. Both Verbeek and Grout (1992) and Monson and Parnell (1992) ascribe the formation of these dikes to high formation pressures that cause natural hydraulic fracturing and injection of liquid bitumen into the fracture zones.

THE GREATER MONUMENT BUTTE OIL FIELD

This enhanced recovery project specifically targeted sandstone reservoirs in the Travis, Monument Butte and Boundary units (Fig. 3-1) that constitute the Greater Monument Butte field. Producing reservoirs within the Green River Formation are discontinuous sandstone bodies, hence, correlation of individual sandstones between adjacent wells is often difficult. The common practice in this portion of the basin is to formulate a stratigraphic nomenclature that is consistent within a field. Regional marker beds have been identified (Fouch, 1981; Colburn et al., 1985) and can be used in correlating between producing fields.

Although the discontinuous nature of many of the sandstone reservoirs has made it difficult to predict their thickness before drilling, the large number of reservoir units has allowed most wells to be completed for production.

Type Log (Monument Butte Federal #13-35)

Figure 3-3 is a log of Monument Butte Federal #13-35 that shows the local stratigraphic nomenclature that will be used in this report. Note that this nomenclature is specific to Lomax Exploration. Other companies active in the area use different terms, but the stratigraphic markers used are largely the same. The sands between the marker horizons have been designated A, B, C, D, and Lower Douglas Creek. These designations will give a gross picture of the sandstone thickness within the interval, but a more detailed breakdown of A_1, A_2, etc. is needed to understand the geometry of the sandstone bodies that will be the subject of the water flood.

The top of the Wasatch Formation is located at 6357 feet in the type log. There is no oil production from the Wasatch Formation in the Lomax property although it is productive for gas in many fields in the basin. Above this is a thick carbonate sequence that is termed the basal Green River Limestone. This unit is approximately 150 feet thick.

Above the basal Green River Limestone is a section of sandstones and carbonates that is termed the Black Shale Facies (Colburn et al., 1985). In Lomax's terminology, this is the Castle Peak section, and it terminates at a prominent carbonate marker bed known as the Castle Peak

Limestone. The Castle Peak section is about 330 ft thick and contains sandstones that produce hydrocarbons, however, these reservoirs are not part of the current water flood project.

The next prominent marker is the "B" Limestone. In the 475 ft section between the Castle Peak and the "B", a number of productive sandstones are often encountered. These are termed the Lower Douglas Creek (LDC) Sandstones. The LDC sandstones are thin in the Monument Butte Unit, but thicken considerably to the west to form important reservoirs in the Travis Unit. In the upper part of the section, thin (generally less than 10 feet thick) channel sandstones constitute the "A" Sandstones.

The prominent marker above the "B" Limestone is termed the Bicarb or B1 Carbonate. In the section between these two markers, sandstones termed the "B" Sandstones constitute important petroleum reservoirs in the Greater Monument Butte area.

The 240 ft thick section between the Bicarb and the Douglas Creek markers contains the most important sandstone reservoir units in the Monument Butte unit. The lower part of this section contains the "C" Sandstone. Above this are three "D" sandstone sections which are named in ascending order "D_3", "D_2" and "D_1". The character of the Douglas Creek Marker can be inferred from imaging logs in the #10-34 and #14A-28 wells. The unit is thinly bedded and consists of carbonate and siltstone. In both wells, the Douglas Creek marker is fractured. These fractures probably contribute to the occasional high values observed on the porosity log.

Figure 3-4 is a structural contour map constructed on the top of the Douglas Creek marker bed. This map shows the general northwest dip of the reservoir section, toward the axis of the Uinta Basin.

Regional Stratigraphic Correlation

Correlation with the regional terminology of Fouch (1981) is based upon interpretation of available logs from the Duchesne Field to the west of Monument Butte. The significant marker horizons occur at the contact between the Green River Formation and the underlying Wasatch Formation, and at the contact between the Black Shale Facies of the Lower Green River Formation and the Green Shale Facies of the Upper Green River Formation (Wiggins and Harris, 1994). Fouch's (1981) "Top of the Carbonate Marker Unit" is equivalent to the "Bi-Carbonate Marker" in Lomax's terminology that separates the Lower, from the Upper, Green River Formation.

The following sections discuss the more important reservoir units in the greater Monument Butte field. The Lower Douglas Creek and D sandstones were the principal focus of this investigation, and are therefore discussed in greater detail than the other units. As a general note, the net sandstone isopach maps included in the detailed discussion are characterized as having >10% neutron log porosity and a gamma ray response of <105 API.

BOREHOLE IMAGING LOGS

Borehole imaging logs commonly use either acoustic impedence or electrical resistivity to image the inside of a borehole. Importantly, the features imaged by the logs are oriented, providing a method for describing and characterizing both sedimentologic and structural information. In this project, the Formation MicroImager (FMI) log of Schlumberger was used. This is a high-precision electrical resistivity imaging tool with a total of 192 microresistivity sensors. The sensors are arranged on four arms and provide appoximately 80% coverage of an 8-inch diameter well.

Structural and stratigraphic features are generally planar, and cut a borehole that is, in general, cylindrical. The image log is displayed unwrapped, with a horizontal axis between 0 and 360 degrees. This display convention is shown schematically in Fig. 3-5. When the borehole image is displayed flat, the planar element takes the form of a sinusoid whose amplitude is a function of the dip angle of the planar feature and whose trough is located in the direction of dip. By convention, the orientation of the planar element will be designated as dip angle and dip azimuth. The utilization of a workstation to analyze the features on the log allows for the efficient collection of large data bases of dip information.

Although borehole imaging logs were originally used for structural interpretation, there has recently been an emphasis on stratigraphic interpretation. In this project, imaging logs were used to determine sedimentary structures, depositional facies, and paleocurrent directions to evaluate depositional environments and sand body geometries. We also use these logs to determine the character and orientation of fractures. We have found it more useful to plot orientation data as dip angle or dip azimuth as a function of depth (Bengtson, 1981; Nielson et al., 1992) rather than the more traditional tadpole plot. We also use the dip versus azimuth (DVA) cross plot of Bengtson (1981) to help characterize stratigraphic orientation data. In general, all data used for stratigraphic interpretation will have the structural dip removed, restoring orientation, as much as possible, to that of the depositional environment.

The FMI log was run through parts of the reservoir interval in the following wells: Travis Federal #14A-28 and #5-33, the Monument Federal #7-34, #9-34 and #10-34, and the Boundary Federal #12-21 (Fig. 3-5). Data from the #7-34 well were lost by the contractor and, therefore, are not available for quantitative interpretation. The FMI provided bed resolution of less than one inch, more definitive lithology, and most important, good definition of fracturing or faulting with the ability to determine the azimuth of the fractures. Some of the more general aspects of interpretation will be discussed in this section while the more detailed stratigraphic interpretation will be presented below.

Table 3-1 lists the intervals where FMI logs were run, and it also shows the regional dip interpreted from the logs. This dip has been removed for discussions of depositional orientation. The regional structural dips are small throughout the Greater Monument Butte area where the study wells are located to the south of the Duchesne fault zone. Information from the Duchesne field to the west (Fig. 3-1 and Nielson et al., 1993) shows that the Duchesne fault acts as a hinge with dips similar to that at Monument Butte to the south of the fault and higher dips (7^o - 8^o) to the north of the fault.

MAGNETIC RESONANACE IMAGING LOGS (MRIL)

The Magnetic Resonance Imaging Log (MRIL) is a relatively new tool that may prove to be very valuable in the evaluation of petroleum reservoirs. This log is a product of NUMAR Corporation, and is described in several publications (Miller et al., 1990; Coates et al, 1991). The log uses magnetic resonance imaging to determine porosity, irreducible fluid saturation and fluid diffusion coefficients in a manner that is independent of lithology.

Magnetic Resonance Imaging Logging (MRIL) was used on five wells. Three of the wells were in the Monument Butte unit and one each in the Boundary and Travis units. Two additional wells were scheduled to be logged with the MRIL, but in one case the salinity of the mud was to high, and in the other case deteriorating hole conditions precluded running the log. The logs were run in 1992, 1993, and 1994. The primary purpose of running the logs was to determine if this log could give an indication of permability and if it could indicate moveable oil and water.

The Federal 10-34 located in the NW SE of Section 34 T8S, R16E Duchesne County, Utah was the first in the program to run the full suite of logs designed to aid in reservoir characterization, and provide an evaluation of MRIL, and the Formation Micro Imager [FMI]. In addition Rotary Sidewall Cores were taken so that log data could be compared directly to actual reservoir rocks. The full suite of logs included the Dual Laterolog-Gamma Ray, Litho Density-Compensated Neutron-Gamma Ray, Formation Micro Imager-Gamma Ray, and the Magnetic Resonance Imaging Log. There was reasonable correlation between the comparable traits of the logs, but certain features of the new logs were not available on the conventional resistivity, and porosity logs. The MRIL provides good effective porosity data, but the main function of this log is to provide more data on effective permability, and the mobility of oil water in the reservoir. In the Federal 10-34, at a depth of 5796 to 5816, the density curve exhibited a porosity of 13 to 16 percent: however the gamma ray, and the compensated neutron indicated possible shaley sand. Rotary sidewall cores at 5800' and 5810' indicated porosity of 14.8 and 10.6 percent respectively. permeability was .43 and .15 md. The lithology of both cores was described as Ss, lt gy, vf-f gr, calc. The conventional log interpretations and core data was similar to other sands in this interval in other wells in which completion attempts were not successful. In this case the MRIL log indicated 8 to 13 percent porosity and 6 to 35 md permeability. The porosities using side-wall cores in the same interval were about 15% and 11% respectively, while the permeabilities were 0.43 md and 0.15 md. It was observed in the reservoir simulation study that even though reservoir permeability, as determined by side-wall cores is very low (usually less than 1 md), the reservoir behaves as if it has higher overall permeability (of the order of 25 md). From that point of view, the MRIL permeabilities are more indicative of the actual reservoir permeabilities. The moveable hydrocarbon curve indicated commercial volumes of oil and no moveable water.

DESCRIPTION OF RESERVOIR UNITS

Lower Douglas Creek Sandstone

The Lower Douglas Creek (LDC) interval lies between the B Limestone and the Castle Peak markers. The thickest accumulations of Lower Douglas Creek sandstones occur in the western portion of the Greater Monument Butte field (Fig. 3-7). As shown in this map, the LDC is characterized by discontinuous sandstone bodies that can reach over 100 feet in net thickness. The LDC sandstones are normally oil-saturated and are often productive reservoirs. The unit forms in an approximate east-west trending belt and is an important oil producer as far west as the Duchesne field (Fig. 3-1).

The LDC has been characterized through a variety of techniques including core description, net sandstone isopach mapping, well log correlation and porosity and permeability measurements on core. In addition, our knowledge of the geology of the LDC has been greatly improved by the collection of Formation MicroImaging (FMI) logs in the Travis Federal #14A-28. Facies analysis based on the FMI log allows interpretation of the sandstone beds below the depth where core was collected. In addition, orientation data for both depositional trends and fracture analyses were determined from the imaging logs through the entire LDC section.

As part of this project, a continuous core was collected from the upper portion of the LDC sandstone from depths of 5550 to 5646 feet in the Travis Federal #14A-28. This is one of the few continuous, full-diameter cores from this important reservoir unit, and the core has been described and analyzed in some detail. The core description and inferred depositional origins for the sedimentary facies are shown in Figure 3-8. A more detailed lithologic log is presented in Appendix A. Small amounts of continuous core are also available from the LDC in wells #6-33 and #2-33 from the Travis unit.

The core collected in the Travis Federal #14A-28 represents deposits of sediment gravity flows (Lutz et al., 1994). The core is comprised of two packages of planar-laminated fine-grained sandstone that exhibit various degrees of dewatering and soft-sediment deformation, which are separated by thin disrupted or massive very fine grained sandstone and siltstone beds (Fig. 3-8). The planar-laminated sandstones occur in 15 ft thick packages with an intraclast-rich base and a dewatered top, and are interpreted as moderate to low-density turbidite channel deposits. One of the packages, from 5632.7 to 5623.5 ft forms a complete Bouma sequence (Bouma, 1962). Both of the planar-laminated sandstone units are strongly oil-stained.

In the following discussion, classification of the type of mass transport (slump, debris flow, grain flow, fluidized flow, and turbidity current flow) is based on sedimentologic criteria established by Nardin et al. (1979). The LDC Sandstone in well #14A-28 consists of nine lithofacies that are described in Table 3-2.

Although planar-laminated fine grained sandstones may occur in many different depositional environments, it is the association of this facies with the other facies in complete and incomplete Bouma sequences that allows the interpretation of their origin as turbidite deposits.

The lower thick turbidite unit has been divided into the various Bouma units based on the vertical sequencing of facies (Fig. 3-8). The sixfold subdivisions of the turbidite units (T_a through T_{et}) are based on a modified Bouma sequence (Bouma, 1962; Scholle and Spearing, 1982). The base of the turbidite channel from 5632.6 ft to 5631 ft is characterized by disrupted medium to fine-grained sandstones with abundant flat shale rip-up clasts. This facies represents the T_a unit. The bulk of the channel from 5631 ft to 5626 ft consists of dewatered laminated fine grained sandstone that represent the T_b unit. Ripple laminated fine grained sandstone occurs from 5626 ft to 5625 ft and can be interpreted as the T_{cd} units. The top of the channel sequence up to 5623.7 ft is composed of massive very fine grained sandstone and siltstone with abundant very fine clasts. The association of this facies with the underlying units suggests its formation as a Bouma T_{et} unit rather than as a separate grain flow.

Above this classic turbidite channel sequence is a sequence of disrupted fine grained sandstone beds with abundant very fine clasts that are interpreted as debris flow and grain flow deposits, each about 2 to 3 ft thick (from 5614.2 ft to 5623.7 ft). Above this debris flow-grain flow sequence and below the next thick turbidite channel sequence (from 5607.3 ft to 5614.2 ft) is a stack of disrupted laminated fine grained sandstone beds that are interpreted as slumped thin turbidite units or fluxoturbidites, each about 3 to 4 ft thick. Because the lithologic contacts within the debris flow sequence and within the slumped sequence are gradational, it is difficult to subdivide these sequences into individual flow units.

The overlying thick turbidite unit does not appear to have been deposited as a result of fluidized flow. Overlying an intraclast-rich base, the planar-laminated fine grained sandstone is not disrupted by any dewatering or slumping features from its base at 5603 ft up to 5590.1 ft (15 ft thickness). From the slightly rippled top of this unit to the top of the cored interval are thin slumped and rippled calcareous sandstone beds and finer-grained silty mudstones.

The increase in bioturbation, ripple lamination and carbonate content in sandstones upward suggests a shallowing-upward facies succession. The fluidized turbidite channels, debris flows and slumps in the lower portion of the LDC Sandstone suggest deposition along the upper part of a sublacustrine slope. The upper less deformed (and possibly, less channelized) turbidite sandstone unit and generally fining-upward sequence suggests shallower deposition in a marginal lacustrine environment.

Below the cored intervals, our knowledge of the LDC sands is based on analysis of FMI logs from well #14A-28, core and facies descriptions from well #2-33 and well log correlations across the Travis unit. Figure 3-9 shows the dip angle and dip azimuths as a function of depth interpreted from the FMI log. The zones of slumping are clearly evident from the high dip angles measured. Note that these zones generally correspond with dip directions to the northwest (Fig. 3-10). This is approximately at right angles to the trend of the thickest accumulation of Lower Douglas Creek sandstones (Fig. 3-7). Both the paleocurrent data and the sandbody morphology suggest that the thick LDC sands represent sublacustrine fans.

Figure 3-11 illustrates the geometry of the sandy portion of the LDC along a southwest-northeast cross section that uses the B Limestone marker as an elevation datum. Overall, the sandstone appears to have a funnel-shaped geometry, with a localized, channelized base and a flat, more widespread top. The turbiditic sandstones beds described in the #14A-28 core represent only the upper half to third of the sandy portion of the LDC section, or the flat top of the unit. There is a thick (up to 60 ft) sandstone bed present below the cored interval in wells #3-33 (5650-5700 ft), #14A-28 (5646-5690 ft), and #15-28 (5660-5740 ft). Generally, the shape of this sandstone interpreted from the gamma-ray logs indicates a fine base and a fining-upward top, which could be consistent with its origin as either a thick slump or a channel with shale rip ups at its base. The base of the sand appears to cut into relatively flat, underlying units.

In well #2-33, core from the LDC (Appendix B) appears to represent slumped debris flow and fluxoturbidite deposits that correlate with the thick slumped sandstone unit in wells #14A-28 and #3-33, located directly to the west. The lower portion of the core from #2-33 (5677 ft to 5669.5

ft) is mostly shale with a few thin (less than a ft thick) slumped sandstone beds. From 5669.5 to 5659 ft, there are four stacked debris flow units composed of muddy, medium-grained sandstone with variable sizes of shale intraclasts which are distributed randomly through the sandstone. Steeply dipping silty laminations are present in thin shales between the sandy debris flow units. The upper portion of the core from 5659 ft to 5650 ft consists of thick (2-5 ft) beds of clean, laminated, fine-grained sandstone with abundant dewatering features (pipes and synsedimentary microfaults). These sands are interpreted as slumped fluxoturbidites, as the laminations are disrupted, and some, steeply inclined (up to 70%).

In well #14A-28, the section of the image log that correlates to the lower portion of LDC appears to represent slumped channel sands. Convoluted laminations and high-angle cross-laminations are present in the thick sands between 5645 ft and 5689 ft. The bases of the channels and the crossbedding suggest depositional trends to the north. In addition to the sedimentary structures evident on the image logs, large-aperture fractures are present from 5660 ft to 5675 ft and from 5700 ft to 5710 ft. In shales below 5710 ft, isoclinal folds can be recognized on the image log. These folds probably represent local deformation associated with loading caused by the deposition of the overlying LDC sands.

Most of the beds between the Castle Peak and the LDC Carb markers can be traced continuously across the Travis unit (Fig 1-12). Successive landward pinchouts of thin beds to the southwest below the LDC Carb may indicate onlapping with a baselevel rise and lake expansion. The LDC Carb marker shows a good coarsening-upward pattern, wave-working and a shallowing-upward sequence. The LDC Carb may represent the capping phase of the lake level rise.

The LDC sand exhibits an erosive base that cuts into relatively flat, underlying units. This downcutting implies a lacustrine lowstand. In wells #15-28 and #10-28 (Fig. 3-11), another channel sand body appears to overlie the basal sandstone unit. This vertical stacking of channels implies a lacustrine highstand and backfilling of the channel scour with the subsequent rise in lake level. The deposition of the sediment gravity flows (slumps, turbidites and sandy debris flows) probably occurred during a wet climatic cycle, when both water and sediment inflow was high and the lake was deep.

The correlated well logs in Figure 3-11 show that the turbiditic and debris flow sands in the upper portion of the LDC sand are relatively flat-lying and uniform in thickness compared with the channel-fill sands in the lower part of the sandbody. The basal turbidite can be traced up onto the proposed shelf or margin of the lake (Fig. 3-11, well #4-33), but the underlying channel-fill sands can not. This would imply that the channel scour was filled by the slumped sands by the time the turbidite unit was deposited.

The calcareous sands that cap the LDC interval seem to have a channelized, fining-upward base and a wave-worked, coarsening-upward top. Overall, the entire LDC section appears to represent a shallowing-upward sequence.

When the B Limestone marker is used as an elevation datum as it is in Figure 3-11, the Castle Peak marker shows a systematic offset that appears to relate to the thickness of the overlying LDC sands. Figure 3-12 is a crossplot of the LDC net sandstone thickness versus the thickness between the B Limestone and the Castle Peak markers. This plot suggests that the deepest channel incisions, produced during the lake lowstand, provided the most accomodation space for the deposition of the gravity flow sands.

To summarize, our studies of the Lower Douglas Creek indicate the following depositional history for this relatively unusual lacustrine sandstone. The LDC sands appear to have been deposited as slumps, debris flows, and turbidites in sublacustrine fans during a lake highstand

and wet climatic cycle. The geometry of the fans suggest a funnel shape, with a slumped, channelized base and a laterally more extensive top. The occurrence of these fans appears to have been controlled by the location of deep channel incisions which were produced during a previous lake lowstand. These channel incisions into marginal lacustrine deposits occurred along an east-west trending zone that may be related to the Duchesne fault zone. The Duchesne fault zone may have acted as a knickpoint for both the creation of the lowstand incised channels and the subsequent loci of deposition for the highstand gravity flows.

The reservoir potential of the LDC Sandstone has been assessed using five core plugs in the upper portion of the sandstone interval from well #14A-28 and from seven samples taken from the #2-33 core, representing the lower portion of the sandy interval. These plugs have been analyzed by the following methods: the measured porosity, permeability and saturations by Dean-Stark analysis (Table 3-3) and visual examination by petrographic techniques.

The most strongly oil-stained sandstones are those that are planar-laminated, whether or not they are disrupted or undeformed. Presumably, these laminated facies are also the best reservoir units. Moderately stained sandstones of the lower turbidite channel sequence have oil saturations that range from 49.6 to 40.5%, horizontal permeabilities in the .46 to .77 md range and vertical permeabilities in the .50 to .99 md range. The plug from 5638 ft has the highest vertical permeability (Table 3-3) of any of the measured samples because the laminations are steeply inclined at this depth. Porosities in this facies range from 9 to 11.7%.

Strongly oil-stained planar-laminated sandstones in the upper turbidite unit are 67 to 70.7% oil saturated. Horizontal permeabilites in this sandstone unit are much higher than those of the lower turbidite unit and range from 2.5 to 13 md. Porosities range from 14.8 to 16.6%.

Calcite and dolomite cement the planar-laminated sandstones. By XRD analysis, the lower turbidite sandstone unit contains between 13 and 18% calcite and dolomite. In contrast, the upper sandstone unit contains 7 to 8% calcite and dolomite cement. Petrographically, these sandstones appear clean and well sorted. The grains are angular to subangular and most of the primary intergranular porosity is preserved in the sandstones. Some compaction effects are evident where mica grains and shale intraclasts drape or deform around the quartz and feldspar grains. Minor quartz overgrowths can be observed, but the dominant authigenic cements are calcite and dolomite. Dissolution of feldspars, especially in volcanic rock fragments, has created some secondary porosity in the sandstones.

X-ray diffraction analysis indicates that most of the clay in the planar-laminated sandstones consists of non-swelling illite (and fine mica) and chlorite. Petrographically, the chlorite can be attributed to chloritized detrital biotite. The illite and mica are detrital rather than authigenic clays. Two samples were found to contain illite-rich mixed-layer illite-smectite (from 5615 and 5639 ft). Thin-sections from these depths contain thin shale laminations or shale rip-up clasts.

The sequence of diagenetic events for the upper portion of the LDC Sandstones appears to be 1) early quartz overgrowths, 2) dolomite cementation with rhombs bridging pores, and 3) calcite cementation. Dissolution of the feldspars probably occurred after the carbonate cementation.

In contrast to clean, laminated sandstones from the upper turbiditic units of the LDC, the sandy debris flow units in the lower LDC contain abundant mixed-layer illite-smectite. The muddy sandstones that make up the debris flows contain between 13% and 19% illite-smectite, as analyzed by X-ray diffraction. The shales in the bottom of the core contain about 53% to 58% illite-smectite. In both the shale and in the clayey sandstone, the clay was probably smectitic and detrital in origin, and has undergone burial diagenesis to an illite-smectite with about 15%

smectite interlayers. Similar to the planar-laminated sandstones in the upper portion of the LDC, the sands that are interpreted to be turbiditic in origin are strongly carbonate-cemented. By XRD analysis, the fluxoturbidites contain about 20% calcite, 3-5% dolomite and a trace to 2% siderite.

"A" Sandstone

The "A" Sandstone is a somewhat arbitrary designation for probable channel sandstones that lie above the Lower Douglas Creek reservoirs. As such, they represent a fall in base level and superposition of a fluvial section above the deeper water turbidites of the LDC. Due to their discontinuous nature, the "A" Sandstones are not currently considered a candidate for water flooding.

"B" Sandstone

The "B" Sandstone is another unit that is currently being produced as part of the Monument Butte water flood. The unit occurs within the stratigraphic interval between the B Limestone and the Bicarbonate markers (Fig. 3-3). There appear to be at least three, and perhaps five, stratigraphically distinct sands. The important sandstones in terms of thickness and porosity are located near the base of the section, above the B Limestone. In some places, thick sandstones occur directly on a truncated and thinned B Limestone, and it is clear that there is an erosional contact. Since the B Limestone is a clearly recognizable unit across the southern portion of the basin, we assume that it represents a stable marginal lacustrine environment.

Figure 3-13 is a net sandstone isopach map of the B_2 sandstone, and physical property measurements are presented in Table 3-4. Correlations between adjacent wells suggests this unit represents a meandering channel system. The relationships shown in 3-13 suggest it is a distributary channel system in a lower delta plain environment. Note also that the isopach shows accumulation along an east-west zone, similar to that of the LDC sandstone (Fig. 3-7). The northwest trend of the thickest portions of the B sandstone in the Monument Butte unit are noteable (Fig. 3-13). This trend is parallel to the trends of gilsonite dikes, which are younger than the channel system, but the two may have resulted from similar structural controls. From the standpoint of the water flood, the sandstones are probably well confined by shale horizons providing a good geometry for the water flood sweep.

"C" Sandstone

The next prominant reservoir unit above the B is the C sandstone. The C sandstone is present in about one half of the wells in the project area. It is normally thin, but is over 30 feet thick in some wells (Fig. 3-14). To the south of the Monument Butte unit, this sandstone forms a very prominant northeast trending thick accumulation. The C sandstone is not being produced under water flood at the present time in the project area.

"D" Sandstone

The "D" sandstone lies above the "C" and is the principal target for water flood in the project area. A discontinuous channel sandstone, the "D_2" is only of minor importance. However, the "D_1" sandstone is thick, widespread and continuous as shown on the net sandstone isopach map (Fig. 3-15).

The "D" Sandstone interval has been characterized from full-diameter core taken in the Monument Federal #6-35 and #12-35 wells (Davies, 1983; Lomax files). Davies characterizes these sandstones as "deposits of a playa environment formed along the margins of a larger permanent lake. Terrigenous clastics were carried onto the playa by unchanneled sheetfloods and braided fluvial channels."

Although no continuous core of the D_1 Sandstone has been taken, detailed description of the sandstone is possible from the FMI image logs from wells #9-34 (Fig. 3-16) and #10-34 (Fig. 3-17) in the Monument Butte Unit. Through identification of sedimentary structures and bedding contacts on the images, the FMI logs can be used to create a lithologic log and to interpret depositional facies, just as this information would be obtained from a core description. In addition, the borehole imaging logs can be used to orient features such as fractures and bed boundaries and allow the estimation of fracture apertures and sandstone bed thicknesses.

In well #10-34, two 6-7 ft thick sandstone beds comprise the D_1 reservoir (Fig. 3-17). On the image logs, both sandstone beds appear to be finely planar laminated with some coarser and more calcareous laminations near the middle of the bed, and ripple laminations at the top of the beds. The basal contacts with shale are sharp but planar. The upper contacts exhibit some relief with a rippled or cross bedded top. In well #10-34, the sandstones are separated by thin shales interbedded with rippled to burrowed siltstones. In well #9-34 (Fig. 3-16), two upward-coarsening sequences (7-9 ft thick) are present, from shale at the base, to interbedded planar-laminated siltstone and shale, to sandstone upward. These sands are interpreted to represent open lacustrine bars near a deltaic environment.

Petrography of sidewall core plugs from the sandstones reveals the presence of abundant rounded micrite clasts and micrite-coated quartz and feldspar grains that suggest formation of the grains in a marginal lacustrine environment and then transportation into the open lake. The overall fine grain size and lack of strong normal grading preclude deposition as channelized sands. The textures observed on the image logs are similar to those in cores of the upper black shale facies of the Green River Formation described by Wiggins and Harris (1994). They describe siliciclastics that alternate with carbonates arranged in a cyclical fashion. These siliciclastic cycles are thought to reflect increases in the supply of silt to very fine sand to the nearshore lacustrine environment during periods of high fluvial discharge, while the sedimentary structures are typical of migrating sand bars. Because there is no erosion at the cycle bases, they envision sands/silts spewing out of channels that emptied into the lake from a delta-front environment.

The bar crests are represented by the coarsest part of the cycles. These are the slightly coarser laminations recognized in the middle of the sandstone beds on the image logs (5008 ft and 4998 ft in #10-34). Where the base of the bar crest facies is sharp into underlying rippled siltstone (such as at 5007 ft in well #9-34), the presence of an erosive pan out in front of the bar crest is indicated. The rippled silty upper parts of the cycles (such as 4995 ft in well #10-34) are interpreted as the lee side of bars riding up over the bar crest.

Bed orientations from the D_1 reservoir in wells #9-34 and #10-34 interpreted from the FMI logs are summarized in Fig. 3-18. The data from the #10-34 shows a bedding orientation of about 80^o while the orientation of beds in the #9-34 is much more scattered. This absence of strong orientation is probably a function of the high degree of reworking of the sediments.

Petrographically, laminations in the core plugs are commonly symmetrically graded, with the coarsest sand in the middle of the lamination. These fine laminations are also observed on the image logs of the D_1 sands. Wiggins and Harris (1994) describe pulses of sandstone and siltstone that are characterized by repetitions of uniformily 1 cm-thick, sand-silt rhythms without any jumps in grain size or evidence of truncation. They interpret these sedimentary structures as a result of continuous sedimentation in the delta front, without wave reworking or erosion, possibly as a result of storm deposition and high stream discharge from the fluvial source area.

An isopach of the D_1 sandstone (Fig. 3-15) shows a maximum thickness of 34 ft (net) with a general lensoid shape oriented WNW-ESE. Although thicker portions of the body occur as a single unit, sections through the margins show that as the body gets thinner, it also breaks up into two or three separate sands separated by shale horizons that are 2-4 ft thick. The position of well #10-34 along the western margin of the body is consistent with the interpretation of the D_1 sands as sublacustrine bars. The #9-34 well is located slightly closer to the center of the sand body. The coarsening-upward sequences in the D_1 interval in this well are indicative of more deltaic deposition closer to the mouth of the river.

Correlation of well logs along a west-east cross-section through the D interval allows a detailed stratigraphic analysis of the sandstone facies. Figure 3-19 shows the gamma-ray logs in an east-west section across the thickest portion of the D_1 reservoir. Although the gamma ray logs are of little use in discriminating carbonate from sandstone beds, depositional patterns are indicated by pinchouts and downlap or onlap of individual packages of sediment below the D_1 interval. Packages a-c (Fig. 3-19) show successive westward (lakeward) downlapping in a forward-stepping pattern that is suggestive of falling lake levels. The b package that represents the D_2 sand in well #12-35 is a thin progradational unit. The d beds and the D1 sands are vertically stacked and represent a lake highstand. Hence, in this 50 ft section, one cycle of lake level fall and then, rise is recorded.

The D_1 sands appear to cut down into the vertically-stacked beds, especially in wells #4-35, #10-35 and #2-35 where the sands are the thickest. Because the base of the D_1 sand appears to be erosive and downcutting, the sands could represent a lake lowstand, with an abrupt landward shift in depositional facies from marginal lacustrine carbonates to deltaic sandstones upward. Alternatively, we propose that the D_1 sand represents a highstand delta that formed during a wet climate cycle, as described by Wiggins and Harris (1994). High stream discharge from the fluvial source area could have increased sediment supply to form a delta in the already-expanded lake. Although not definitive, it is likely that the increased amount of sediment was related to a short-term change in climate rather than renewed tectonics in the San Rafael Swell and/or Uncompahgre Uplift.

The reservoir potential of the D_1 sandstone has been assessed using four core plugs from well #10-34 and three core plugs from well #9-34. These plugs have been analyzed by the following methods: the measured porosity, permeability and saturations by Dean-Stark analysis (Table 3-5), the bulk and clay mineralogic analyses by X-ray diffraction techniques (Table 3-6), and visual examination by petrographic techniques.

In well #10-34, core plugs at 5006 ft and 5007 ft from the middle of the lower D_1 reservoir are characterized by very fine to fine sand grains in well-sorted, parallel laminations. The grains are predominantly composed of quartz, plagioclase and potassium feldspar. From the X-ray diffraction (XRD) analysis, quartz makes up 48 wt.% , plagioclase makes up 24 wt.%, and potassium feldspar makes up 10 wt. % of the sample. Minor mica, polycrystalline quartz, volcanic rock fragments, and rounded micrite and micrite-coated grains are also present. The grains are cemented with minor quartz overgrowths and common calcite and dolomite. From the XRD, the calcite and dolomite contents of the sandstone are each 6 wt. %. The porosity types are mostly intergranular with some intragranular porosity in the volcanic rock fragments. Measured porosity is 14%, horizontal permeability is 5.5 md, and the oil saturation is 36%. The clay X-ray diffraction analysis indicates only the presence of detrital clays, chlorite and illite with fine mica.

The sands at top of the D_I reservoir (4989 ft) in well #10-34 are more texturally and compositionally mature, and more strongly carbonate-cemented, than the underlying sands. The rounded to subrounded grains are cemented by quartz as overgrowths, and by carbonates (mostly dolomite) that poikilotopically enclose the grains in some places. Abundant micrite clasts occur along some laminations. There is very little visible porosity. Measured porosity is 5.8%, permeability is .04 md, and oil saturation is 39.9%.

The base of the D_I sandstone in well #9-34 is similar in texture and mineralogy to the D_I in well #10-34, but it has undergone a different cementation history. Extensive, early quartz overgrowth formation can be recognized, calcite cementation is very minor (2-4% calcite by XRD), and the feldspars have undergone extensive dissolution. The result is a porous rock with good intergranular and intragranular porosity. The measured porosity is 13.5%, permeability is 2.7 md, and oil saturation is 51.5%. The upper portion of the D_I sand interval in well 9-34 (4994 ft) is similar to that in well 10-34, with lower porosities and permeabilities as a result of strong quartz and calcite cementation (14% calcite by XRD). In addition, a brown authigenic clay is present in the intergranular pores. From the X-ray diffraction analysis, this clay is a chlorite or a mixed-layer chlorite-smectite.

FRACTURES

The importance of fracturing to petroleum production in the Unita Basin has been recognized for some time (Stearns and Friedman, 1972; Lucas and Drexler, 1976; Chidsey and Laine, 1992). Narr and Currie (1982) studied fracturing in the Altamont field and concluded that, because of low permeability, oil production was dependent upon the presence of extensional fractures. Their evidence suggests that fractures were initiated at about the maximum depth of burial and continued to form as the beds were uplifted. Nielson et al. (1993) documented the abundance and orientation of fracturing in the Duchesne field. These fractures were principally oriented east-west, parallel to the Duchesne fault zone. Northwest- and north-trending fractures are also present. The northwest trending fractures are parallel to the trend of the gilsonite veins, and the north-south fractures may reflect the influence of Basin and Range normal faulting that becomes more prominent on the western side of the Uinta Basin (Fig 1-1).

Studies in the eastern part of the Unita Basin (Verbeek and Grout, 1992) have documented five regional joint orientations. From oldest to youngest, these are: F_1 = N 15°-30° W, F_2 = N55°-85° W, F_3 = N 60°-80° E, F_4 = N 15°-40° E and F_5 = N 65°-85° W. The F_2 and F_4 orientations are characterized as being very abundant and the F_3 event is of moderate abundance. The joints are near-vertical and extend into the Piceance Basin in Colorado (Lorenz and Finley, 1991). Although the gilsonite dikes have an orientation similar to F_2, Verbeek and Grout (1992) concluded that there were significant differences in morphology, age and orientation. They suggest that the gilsonite dikes were forcefully emplaced during the early stages of regional extension following the Laramide orogeny.

The orientation and character of fractures from the Greater Monument Butte area was determined using core from well #14A-28 and FMI logging. A typical example of a fracture imaged in reservoir units is shown in Fig. 3-20. In general, fractures are developed in sandstones and are terminated or decrease in intensity in overlying and underlying shales. Thus, they tend to develop in the more brittle lithologies and are either not formed or preserved in the more ductile units. In most cases, there is no offset of bedding associated with the fractures, and they are more appropriately termed joints (Pollard and Aydin, 1988). These joint-like fractures contribute to horizontal permeability within the sandstone reservoirs, but have little influence on vertical permeability. Lorenz and Finley (1991) found that similar fracturing in Mesaverde reservoirs in the Piceance basin produced a horizontal anisotropy of 100:1. In addition, the horizontal permeability will be anisotropic and can be assumed to follow the predominant fracture trend in a particular well. The process of hydrofracturing during well completion will only increase the effect of fracture-related reservoir heterogeneity.

Fracturing in the LDC Sandstone Identified in Core

The core from well #14A-28 is moderately fractured (Fig. 3-8; Appendix A). In general, fractures are developed in cemented sandstone beds rather than in more ductile, finer-grained lithologies. In the upper portion of the core, fractures are present in carbonate-cemented sandstone beds at 5570-5572', 5582' and at 5589-5590'. In these beds, the fractures are open, subvertical and planar. Fractures in the upper and lower turbidite sandstone units are more irregular. At 5608-5611' and 5625-5627', open fractures are subvertical but tend to mimic the orientation and geometry of dewatering pipes in the laminated sandstones and are nonplanar. The dewatering pipes appear to be oil-stained; the pipes may be filled with migrated fines (clay) that preferentially absorb oil. The correlation of dewatered facies to fractured zones is not strong because many of the dewatered sandstones do not contain fractures.

In general, the open, throughgoing (planar), natural fractures have dips greater than 60%. The dewatering pipes exhibit similar dips and are commonly subvertical. Synsedimentary microfaults also developed as a result of dewatering. However, these microfaults generally dip less than 45% and probably don't extend for appreciable distances.

Fracturing Identified Through FMI Logging

Fractures imaged by the FMI logs are of higher electrical conductivity than the surrounding rock. We assume this results from the ingress of drilling fluid into these zones. The FMI images also suggest that, if the fractures are cemented by calcite or quartz, which are electrically resistive minerals, the cement is minor.

The Boundary Federal #12-21 well has FMI coverage through much of the lower Green River and upper Wasatch Formations (Table 3-1). Interpretation of the imaging log shows that fracturing is ubiquitous through the Green River Formation, but dies out in the upper part of the Wasatch Formation (Fig. 3-21). This stratigraphic distribution of fracturing is similar to that shown for gilsonite veins by Monson and Parnell (1992).

The orientation of fractures determined by interpretation of the FMI log from the five wells that were part of this project are shown in Fig. 3-22. These fracture orientations generally correspond with the F_2 trend of Verbeek and Grout (1992). The east-northeast strike of the fractures is similar to the regional east-northeast trend of faults that cut outcrops of the Green River Formation in the southern part of the Uinta Basin. The strong east-west trend in Monument Federal #9-34 is more closely parallel to the Duchesne fault zone.

The orientations of all the fractures measured in the imaging logs are shown in Fig. 3-23. This diagram illustrates the preponderance of steep fractures. From a statistical standpoint, there is a low probability of intersecting a steeply dipping fracture with a near vertical well. We therefore suspect that the sandstone reservoirs, where the measured fractures predominantly occur, are pervasively fractured. In the Duchesne field, Nielson et al. (1993) reported that a near-horizontal well drilled toward the north encountered fracturing of variable frequency. However, the maximum concentration was nearly 2 fractures/ft in Duchesne, and it is not unreasonable to believe that similar concentrations are present in the Greater Monument Butte field.

The character of fracturing intersected in wells in the Greater Monument Butte field is similar to those described by Lorenz et al. (1991) in the Piceance Basin. These similarities include the lack of shearing, vertical orientation, and their presence in the more brittle lithologies and termination by more ductile mudstones and shales, in addition to the similar orientations mentioned above. Also, we have seen no evidence for the formation of fractures by natural hydraulic fracturing, although that does not preclude the process in zones of overpressuring (Bredehoeft et al., 1992). We subscribe to the model of Lorenz et al. (1991) for the formation of these fractures during burial in an environment of differential horizontal stress with pore pressures approaching the least horizontal principal stress. A possible exception to this may be the fractures that are parallel the Duchesne fault zone. Nielson et al. (1993), in a study of the Duchesne field, did document flexure across this fault that could be the mechanism for the generation of these fractures.

Faulting

Faulting with minor offset was observed in several wells in the project area. Figure 3-24 illustrates an example of one of these faults from the Travis Federal #5-33. There were no large zones of brecciation or offset observed in the imaging logs, and most of the fault activity appears to have taken place during sedimentation.

Figure 3-25 is a stereoplot of the orientation of all faults measured in FMI images from the Greater Monument Butte area. There does not appear to be a strong concentration of fault orientations. The observed faulting may have resulted from localized conditions produced during during sedimentation, which would have little influence on the petroleum production in this area.

CONCLUSIONS

The petroleum reservoirs of the lower Green River Formation owe their character to both sedimentary and structural processes. Stratigraphic information collected during this project has provided detailed information on the origin of the D_1 and LDC sandstone bodies that are the principal reservoirs being exploited by the water flood.

The Lower Douglas Creek reservoir forms isolated sandstone lenses that can reach over 100 feet of net thickness. The sandstones are concentrated in channel scours that formed during a lowstand in lake level. The channel incisions were subsequently filled with slumps, debris flows and turbidites during a lake highstand. The lithologic heterogeneity of this unit, complex reservoir architecture, and pervasive fracturing makes it a less than ideal candidate for water flood. In addition, its localized nature makes it a difficult exploration target.

The D_1 sandstone reservoir formed as a sublacustrine bar complex that was associated with a nearby delta system. In contrast to the LDC sandstones, the D_1 reservoirs are laterally continuous and lithologically homogeneous. This unit provides an excellent geometry and lithology for the water flood project.

The other reservoir sandstones in the lower Green River Formation are fluvial and are not candidates for water flood at the present time. They do, however, contribute to oil production and are important for the overall economics of the field.

The lower Green River Formation in the Greater Monument Butte area reflects deposition from a long-lived fluvial-deltaic system. This river system was developed along the shallow gradient margin of the lake and probably drained the San Rafael uplift to the south. In the marginal lacustrine enviroment, the presence of fluvial and distributary channels reflect lowstands of Lake Uinta. Open lacustrine mudstones and shales that separate the reservoir sandstones were deposited during highstands. In the nearshore environment, most of the deltaic units represent highstand deposits when a wet climate increased the amount of fluvial discharge of sand and water into the lake. It is these deltaic sands in which the water flood has been most effective.

From a structural standpoint, the Greater Monument Butte field is located on the gently dipping flank of the asymmetric Uinta Basin. A structural contour map constructed on the Douglas Creek marker shows the homoclinal dip to the northeast. In contrast to this simple structural setting, the reservoir sandstones within the project area are pervasively fractured. These fractures trend east-west to northwest-southeast and are comparable with the orientations of the regional F_2 fracture set described by Verbeek and Grout (1992) and the orientation of gilsonite dikes. A strong east-west trend in wells #14A-28 and #9-34 may also reflect the influence of the Duchesne fault zone. The fracturing is stratigraphically bound in that the more brittle sandstones are fractured while adjacent mudstones and shales are not. Therefore, the fracturing will produce an anisotropic horizontal permeability in the reservoirs, but will not contribute to vertical permeability. Hydrofracturing during well completion will enhance this permeability heterogeneity.

REFERENCES

Bengtson, C. A., 1981, Statistical curvature analysis technique for structural interpretation of dipmeter data: American Association of Petroleum Geologists Bulletin, v. 65, p. 312-332.

Bouma, A. H., 1962, Sedimentology of some flysch deposits, a graphic approach to facies interpretation: Elsevier, Amsterdam, 168p.

Bredehoeft, J. D., Wesley, J. B. and Fouch, T. D., 1994, Simulations of the origin of fluid pressure, fracture generation, and the movement of fluids in the Uinta Basin, Utah: American Association of Petroleum Geologists Bulletin, v. 78, p. 1729-1747.

Carter, R.M., 1975, A discussion and classification of subaqueous mass-transport with particular application to grain-flow, slurry-flow and fluxoturbidites: Earth Science Review No. 11, p. 145-177.

Castle, J. W., 1990, Sedimentation in Eocene Lake Uinta (Lower Green River Formation), northeastern Uinta Basin, Utah, in Katz, B. J. (Ed.) Lacustrine basin exploration - case studies and modern analogs: American Association of Petroleum Geologists Memoir 50, p. 243-263.

Chidsey, T. C. and Laine, M. D., 1992, The fractured Green River and Wasatch Formations of the Uinta Basin, Utah: Targets for horizontal drilling, in Fouch, T. D., Nuccio, V. F. and Chidsey, T. C. (eds.), Hydrocarbon and mineral resources of the Uinta basin, Utah: Utah Geological Association Guidebook 20, p. 123-134.

Coates, G. R., Peveraro, R. C. A., Hardwick, A. and Roberts, D., 1991, The magnetic resonance imaging log characterized by comparison with petrophysical properties and laboratory core data: Society of Petroleum Engineers paper SPE 22723, p. 627-635.

Cohen, A. S., 1990, Tectono-stratigraphic model for sedimentation in Lake Tanganyika, Africa, in Katz, B. J. (Ed.) Lacustrine basin exploration - case studies and modern analogs: American Association of Petroleum Geologists Memoir 50, p. 137-150.

Colburn, J. A., Bereskin, S. R., McGinley, D. C. and Schiller, D. M., 1985, Lower Green River Formation in the Pleasant Valley producing area, Duchesne and Uinta Counties, Utah, in Picard, M. D. (ed.) Geology and Energy Resources Uinta Basin of Utah: Utah Geological Association Guidebook 12, p. 177-186.

Fouch, T. D., 1981, Distribution of rock types, lithologic groups, and interpreted depositional environments for some lower Tertiary and upper Cretaceous rocks from outcrops at Willow Creek-Indian Canyon through the subsurface of Duchesne and Altamont oil fields, southwest to north central parts of the Uinta basin, Utah: U. S. Geological Survey, Chart OC-81.

Fouch, T. D., Nuccio, V. F., Osmond, J. C., MacMillan, L., Cashion, W. B., and Wandrey, C. J., 1992, Oil and gas in uppermost Cretaceous and Tertiary rock, Uinta basin, Utah, in Fouch, T. D., Nuccio, V. F. and Chidsey, T. C. (eds.), Hydrocarbon and mineral resources of the Uinta basin, Utah: Utah Geological Association Guidebook 20, p. 9-47.

Hintze, L. F., 1980, Geologic map of Utah, scale 1:500,000: Utah Geological and Mineral Survey.

Johnson, T. C., Wells, J. D. and Scholz, C. A., 1995, Deltaic sedimentation in a modern rift lake: Geological Society of America Bulletin, v. 107, p. 812-829.

Lambiase, J. J., 1990, A model for tectonic control of lacustrine stratigraphic sequences in continental rift basins, in Katz, B. J. (ed.) Lacustrine basin exploration - case studies and modern analogs: American Association of Petroleum Geologists Memoir 50, p. 265-276.

Lorenz, J. C. and Finley, S. J., 1991, Regional fractures II: fracturing of Mesaverde reservoirs in the Piceance Basin, Colorado: American Association of Petroleum Geologists Bulletin, v. 75, p. 1738-1757.

Lorenz, J. C., Teufel. L. W. and Warpinski, N. R., 1991, Regional fractures I: a mechanism for the formationof regional fractures at depth in flat-lying reservoirs: American Association of Petroleum Geologists Bulletin, v. 75, p. 1714-1737.

Lucas, P. T. and Drexler, J. M., 1975, Altamont-Bluebell: a major fractured and overpressured stratigraphic trap, Uinta Basin, Utah, in Bolyard, D. W. (ed.) Deep drilling frontiers in the central Rocky Mountains: Rocky Mountain Association of Geologists Symposium, p.265-273.

Lutz, S.J., Nielson, D.L., and Lomax, J.D., 1994, Lacustrine turbidite deposits in the lower portion of the Green River Formation, Monument Butte Field, Uinta Basin, Utah: American Association of Petroleum Geologists Annual Convention Program, v. 3, p. 203.

Middleton, G.V. and Hampton, M.A., 1976, Subaqueous sediment transport and deposition by sediment gravity flows, in D.J. Stanley, and D.J.P. Swift (eds.), Marine sediment transport and environmental management: John Wiley and Sons, Inc., p. 197-218.

Miller, M. N., Paltiel, Z., Gillen, M. E., Granot, J. And Bouton, J. C., 1990, Spin echo magnetic resonance logging: porosity and free fluid index determination: Society of Petroleum Engineers paper SPE 20561, p. 321-334.

Monson, B. and Parnell, J., 1992, The origin of Gilsonite vein deposits in the Uinta basin, Utah, in Fouch, T. D., Nuccio, V. F. and Chidsey, T. C. (eds.), Hydrocarbon and mineral resources of the Uinta basin, Utah: Utah Geological Association Guidebook 20, p. 257-270.

Narr, W. and Currie, J. B., 1982, Origin of fracture porosity- example from Altamont field, Utah: American Association of Petroleum Geologists Bulletin, Vol. 66, p.1231-1247.

Nardin, T.R., Hein, F.J., Gorsline, D.S., and Edwards, B.D., 1979, A review of mass movement processes, sediment and acoustic characteristics, and contrasts in slope and base-of-slope systems versus canyon-fan-basin systems: SEPM Special Publication No. 27, p. 61-73.

Nielson, D. L., Chidsey, T. C., Morgan, C. and Zhao, W., 1993, Fracturing in the Duchesne field, Utah: Importance for horizontal drilling: 1993 American Association of Petroleum Geologists Annual Convention Official Program, p. 156-157.

Nielson, D. L., Lutz, S. J. and Anderson, P. B., 1992, Evaluation of reservoir heterogeneity using the statistical curvature analysis technique: Gas Research Institute, report GRI-92/0321, 141p.

Pollard, D. D. and Aydin, A., 1988, Progress in understanding jointing over the past century: Geological Society of America Bulletin, v. 100, p. 11181-1204.

Ray, R. G., Kent, B. H., and Dane, C. H., 1956, Stratigraphy and photogeology of the southwestern part of Uinta Basin Duchesne and Uinta Counties, Utah: U. S. Geological Survey Map OM 171.

Scholle, P.A. and D. Spearing, eds., 1982, Sandstone Depositional Environments; Continental Slopes by H.E. Cook, M.E. Field, and J.V. Gardner; Submarine Fans by D.G. Howell and W.R. Normark: AAPG, p. 329-404.

Stearns, D. W. and Friedman, M., 1972, Reservoirs in fractured rock, in King, R. E. (ed.) Stratigraphic oil and gas fields - classification, exploration methods, and case histories: American Association of Petroleum Geologists Memoir 16, p.82-106.

Verbeek, E. R. and Grout, M. A., 1993, Structural evolution of gilsonite dikes, eastern Uinta basin, Utah, in Fouch, T. D., Nuccio, V. F. and Chidsey, T. C., eds., Hydrocarbon and mineral resources of the Uinta basin, Utah: Utah Geological Association Guidebook 20, p. 237-255.

Wiggins, W.D. and Harris, P.M., 1994, Lithofacies, depositional cycles and stratigraphy of the Lower Green River Formation, southwestern Uinta Basin, Utah, in Lomando, A.J., Schrieber, B.C. and Harris, P.M. (eds.), Lacustrine reservoirs and depositional systems, SEPM Core Workshop No. 19, Denver, June 12, 1994.

Zemanek, J., Glenn, E. E., Norton, L. J. and Caldwell, R. L., 1970, Formation evaluation by inspection with the borehole televiewer: Geophysics, v. 35, p. 254-269.

Table 3-1. Logged intervals (FMI) of wells in the Greater Monument Butte field

Well	Regional Dip	Depth Interval Logged (ft)
Travis 14A-28	1^0 @30^0 in D zone	2911-3190
		4910-5124
		5480-5780
Travis 5-33	2.2^0 @ 8^0	4430-4470
		4650-4690
		5032-5140
		5410-5480
		5898-5960
		6010-6080
Monument Butte 9-34		3060-3310
		4940-5100
		5290-5420
		5530-6065
Monument Butte 10-34	1^0 @ 30^0	4900-5022
		5458-5530
		5730-5976
		6240-6320
Monument Butte 7-34		5020-5060
		5450-5490
		5530-5580
		5680-5760
		5900-6040
		6080-6130
		6210-6310
Boundary 12-21	0	5175-5809
		6062-6587
		6624-7332

Table 3-2. Lithofacies description of the Lower Douglas Creek Sandstones in core from well Travis Federal #14A-28

Shale	Fissile to conchoidal partings, commonly silty, common at the top of the cored interval.
Bioturbated mudstone.	Rare sand-filled burrows (slightly smeared or deformed) in shaly siltstone, mudstone is interbedded with shale at the top of the cored interval.
Disrupted siltstone.	Variably calcareous siltstone to very fine grained sandstone with vague sandy laminations or mottles that appear slightly deformed. These homogeneous light gray siltstones commonly occur in thin beds between the planar-laminated sandstone units. Their calcareous composition suggests deposition in a quiet marginal lacustrine area.
Ripple laminated sandstone.	Rippled sandstone occurs at the top of thin planar-laminated or dewatered sandstone beds in the upper portion of the cored interval and also at the top of the upper thick turbidite sandstone unit. In the lower sandstone unit, the presence of ripples is attributed to waning current energy after active channel deposition. In the upper portion of the core, the ripples may indicate shoaling-upward channels within reach of wave-base.
Planar laminated sandstone.	Most of the cored interval is composed of well-sorted, slightly calcareous fine grained sandstone in planar laminations. This facies comprises nearly all of the upper turbidite unit where it is also strongly oil-stained.
Dewatered sandstone.	The sandy laminations in this facies are cut by many thin vertical fluid escape pipes, or more rarely, exhibit flame structures. The dewatered sands are common at the top of fine-grained turbidite units (= "fluxoturbidite" of Carter, 1975; Middleton and Hampton, 1976). The bulk of the lower turbidite sandstone unit is composed of this facies, which indicates its deposition as a result of fluidized flow. Compared to the other lithofacies, this one is preferentially fractured where the fractures have propagated along the planes of weakness presented by the fluid escape routes.

Disrupted sandstone.	The sandy laminations in this facies are commonly folded to steeply inclined indicating slumping of originally horizontally-laminated sandstone. The laminations in some of these slumped packages are offset (rarely in an en-echelon pattern) by synsedimentary microfaults. This facies is common to the thin slumped beds between the two turbidite sandstone units and also, in sandstone beds underlying the lower turbidite unit.
Shale rip-ups in sandstone.	Thin beds containing flat to possibly algal-laminated shale clasts are common at the bases of the turbidite sandstone units. They are interpreted to represent the bases of the turbidite channels. The sandstone containing the shale rip-ups is slightly coarser (up to medium-grained) than the overlying sandstone and is commonly carbonate-cemented and less oil-stained than the overlying, more porous sandstone. Some deformation of the laminations and of the shale clasts in this facies may indicate minor loading at the channel bases.
Massive sandstone.	This facies is either massive or contains scattered rounded fine to coarse clasts that are occur in random orientations within the siltstone to very fine grained sandstone. These massive but thin (2-3 ft thick) beds are common above the dewatered fine sandstone at the top of the lower turbidite unit and also below the turbidite at the bottom of the cored interval. This facies is interpreted to represent grain flow to debris flow units.

Table 3-3. Physical property measurements from the Lower Douglas Creek sandstone

Well	Depth (ft)	Permeability (md)		%Porosity	Saturation (%)		Grain Density (g/cc)	Neutron Log Porosity
		Horiz.	Vert.		Oil %	Water %		
14A-28	5595	2.5	.07	14.8	67.0	20.4	2.65	16.3
	5598	13	.43	16.6	70.7	16.4	2.65	15
	5615	0.14	.07	12.5	29.1	44.2	2.66	10
	5638	0.77	0.99	11.7	40.5	20.2	2.66	10
	5639	0.46	0.50	9.0	49.6	34.2	2.66	9
10-34	5800	0.43		14.8	41.8	25.9	2.67	16.2
	5810	0.15		10.6	48.2	16.4	2.69	14.4
9-34	5650	0.11		9.0	64.8	27.4	2.67	14
	5651	0.63		13.1	69.4	12.3	2.66	16.8

Table 3-4. Physical property measurements of the B sandstone reservoir

Well	Depth (ft)	Permeability (md)		%Porosity	Saturation (%)		Grain Density (g/cc)	Neutron Log Porosity
		Horiz.	Vert.		Oil %	Water %		
9-34	5338	0.80		14.4	55.7	20.7	2.66	16.2
	5344	0.03		2.8	75.1	18.7	2.67	7
	5356	0.16		10.4	57.5	20.2	2.69	11

Table 3-5. Porosity and permeability measurements from the D1 reservoir

Well	Depth (ft)	Permeability (md)		%Porosity	Saturation (%)		Grain Density (g/cc)	Neutron Log Porosity
		Horiz.	Vert.		Oil %	Water %		
9-34	4994	0.04		6.3	55.0	24.9	2.66	10
	5004	0.45		11.0	50.1	20.2	2.66	13
	5006	2.7		13.5	51.5	12.5	2.66	15
10-34	4989	0.04		5.8	39.9	18.8	2.67	10
	4998	1.2		13.3	37.6	48.5	2.66	14
	5006	0.60		12.2	47.3	17.4	2.66	15
	5007	5.5		14.0	36.0	39.4	2.66	14

Table 3-6. X-ray diffraction analysis of the D1 reservoir

Sample No.	Quartz	Plagioclase	K- Feldspar	Siderite	Calcite	Dolomite	Pyrite	Smectite	Chlorite	Illite+ Mica	Mixed-layer illite-smectite	Mixed-layer Chlorite-smectite	Amorphous/ Below Detect.	% smectite in illite-smectite	
Well #10-34															
5007.0-08.0 Bulk	48	24	10		6	6			3	3	Tr				
5800.0-01.0 Bulk	43	22	8	Tr	4	7			3	3	10				
Clay									18	10	72			20	
5810.0-11.0 Bulk	50	20	4	2	16	6	Tr		1	1					
Clay									15	54	31			20	
5880.0-81.0 Bulk	54	27	10		2	*3			Tr	1	3				*ferroan dolomite
Well #9-34															
4994 Bulk	36	30	8		14	4				4	Tr	2	2	Tr	
5004 Bulk	48	27	7		4	6		Tr		3	1	2	2		
5006 Bulk	45	35	4		2	3				3		2	6		

Tr = Trace

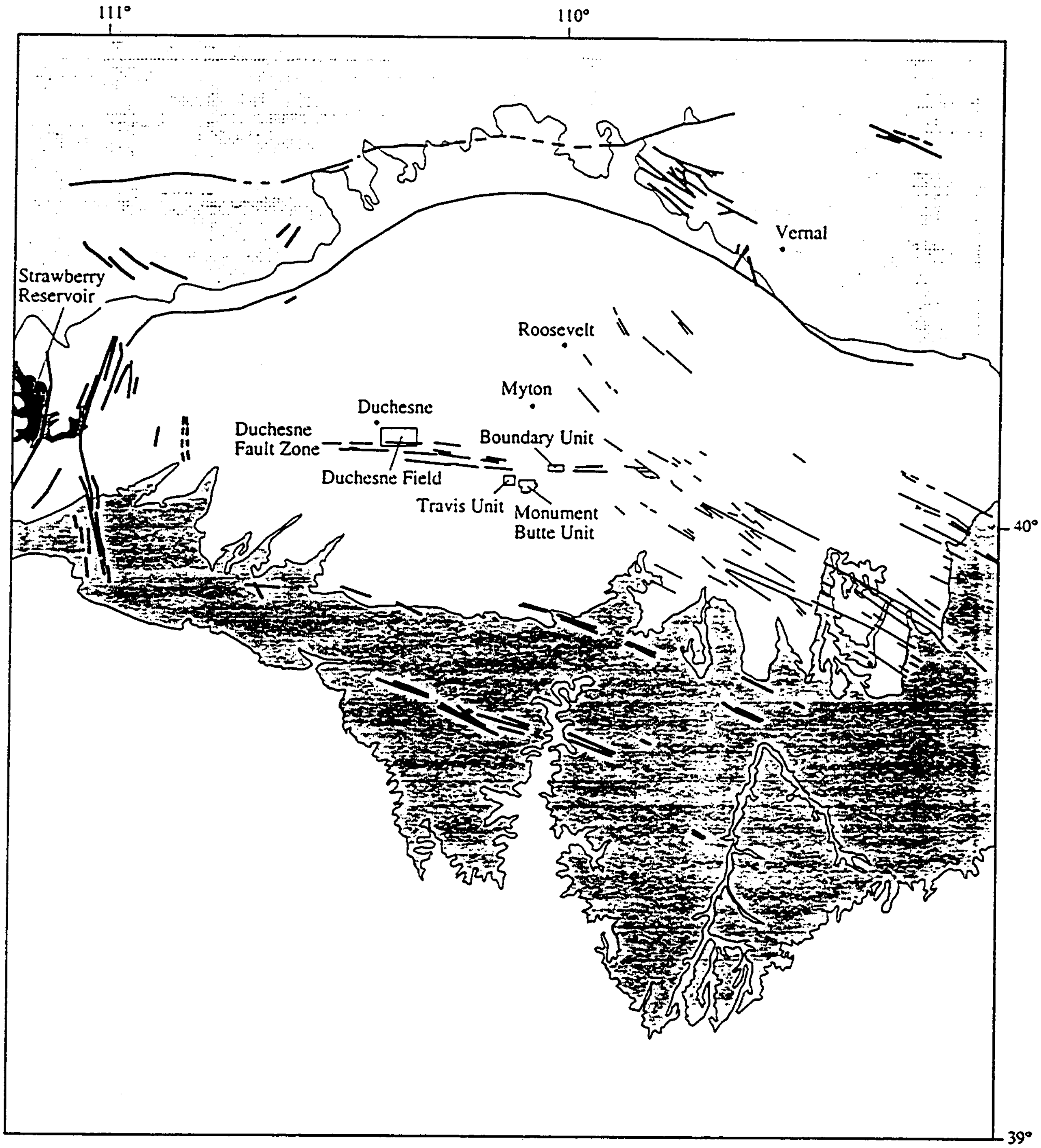


Figure 3-1. Map of the Uinta Basin showing major faults (light dashed lines) and gilsonite veins (heavy dashed lines) after Hintze (1980) and the locations of the oil fields discussed in the text

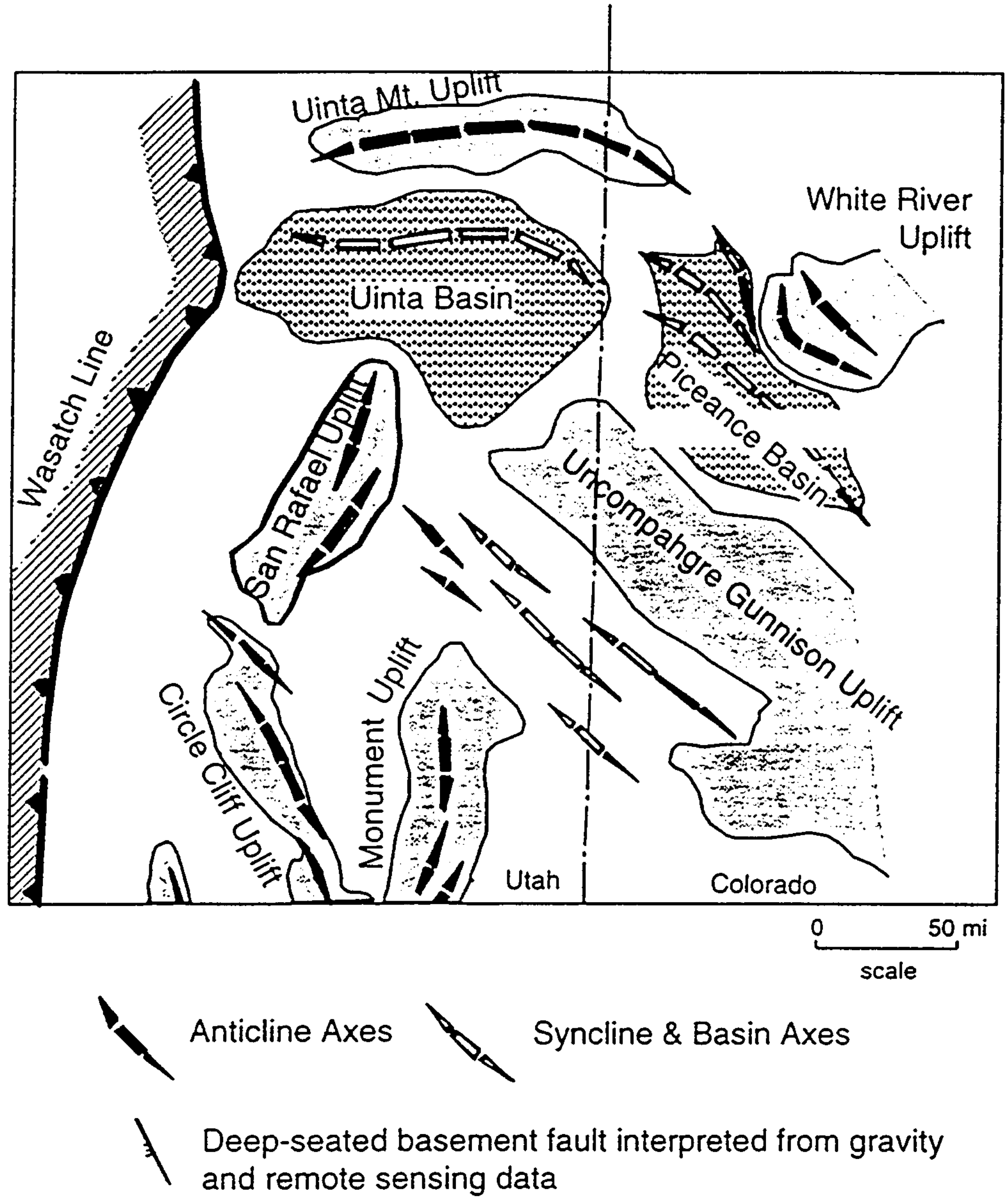


Figure 3-2. Map of the Major Laramide tectonic elements influencing the Uinta Basin

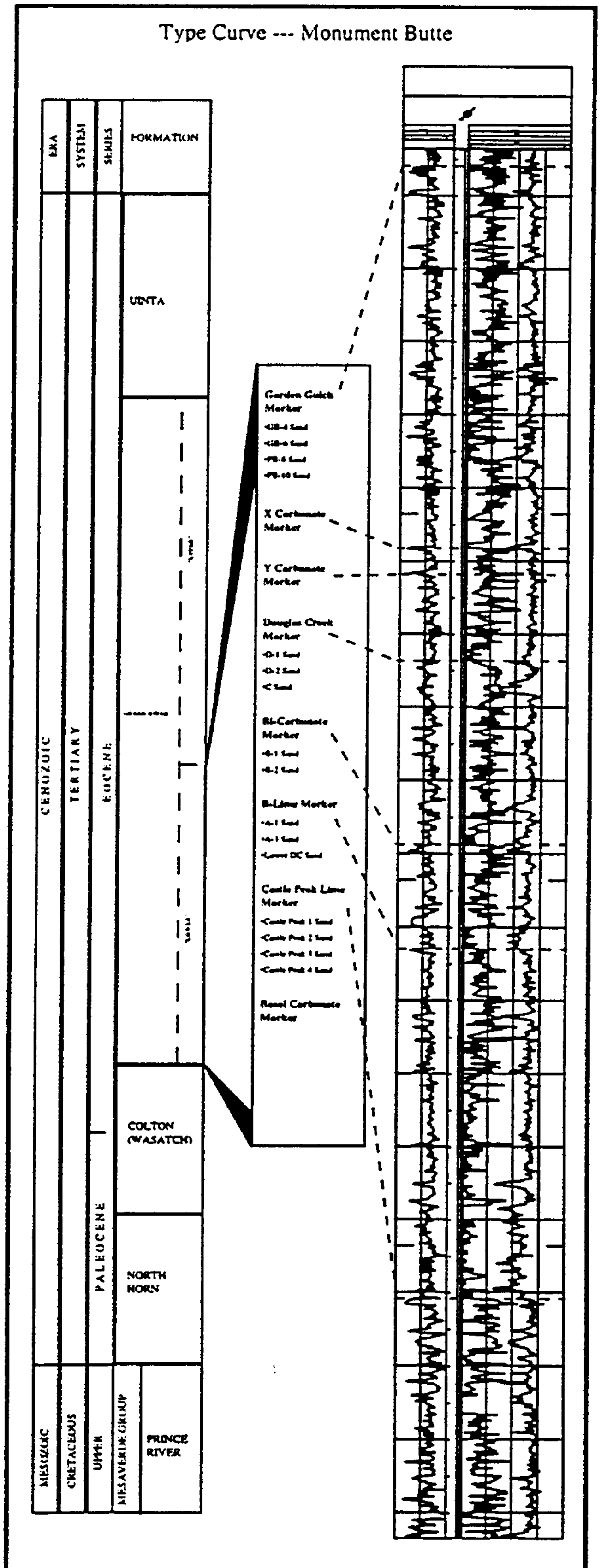


Figure 3-3. Interpreted log (type log) of the Monument Butte Federal #13-35 showing the stratigraphic nomenclature used in this report

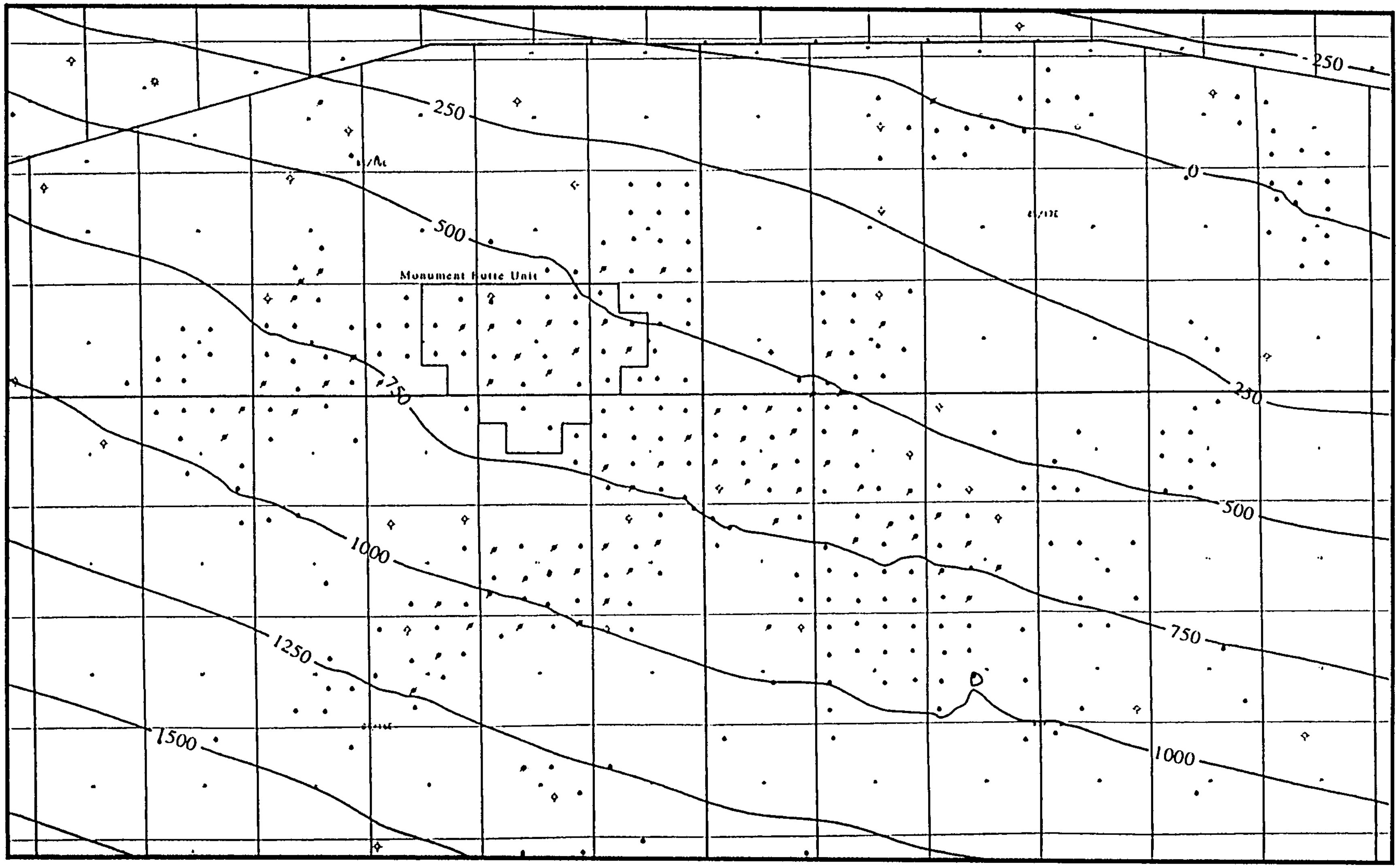
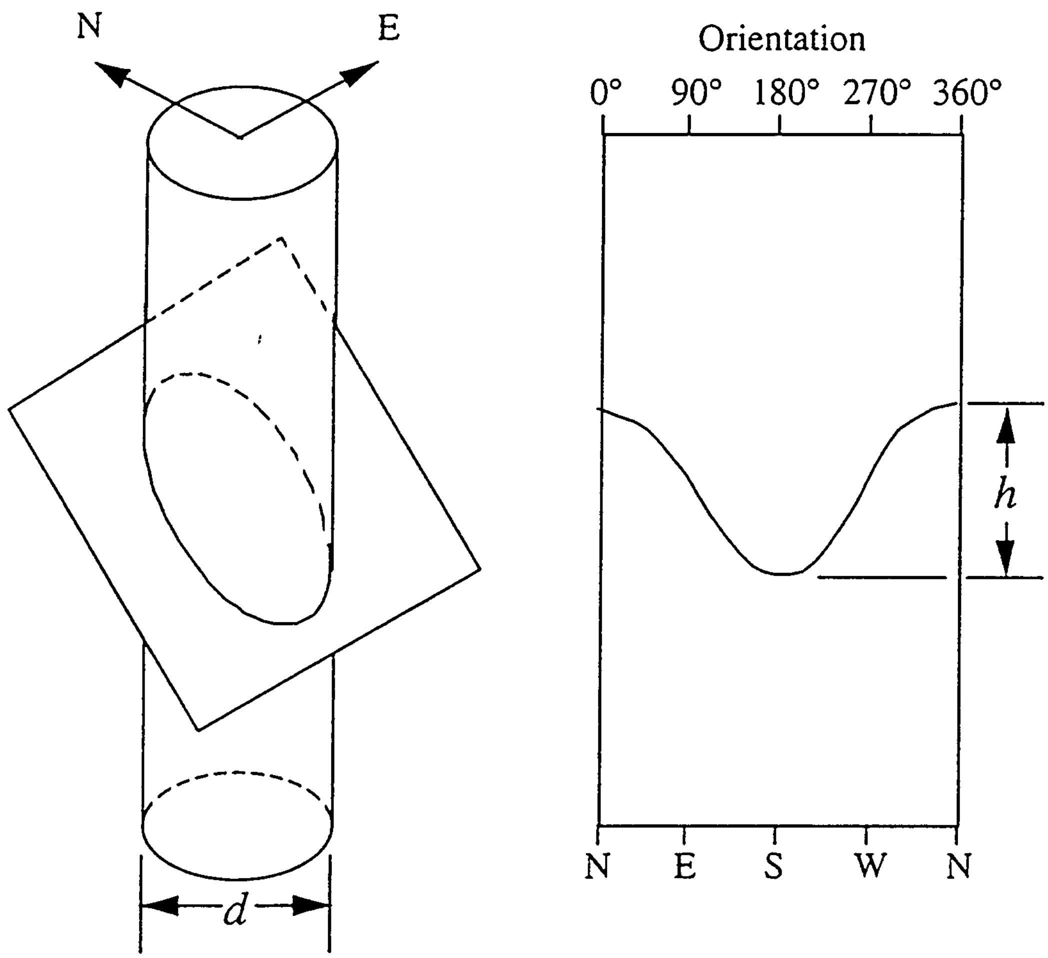


Figure 3-4. Structural contour map constructed on top of the Douglas Creek marker bed



Dip azimuth is trough of sinusoid

Dip Angle = $\tan^{-1}(h/d)$

Figure 3-5. Planar feature intersecting a well bore and borehole imaging log of the feature (modified from Zemanek et al. 1970).

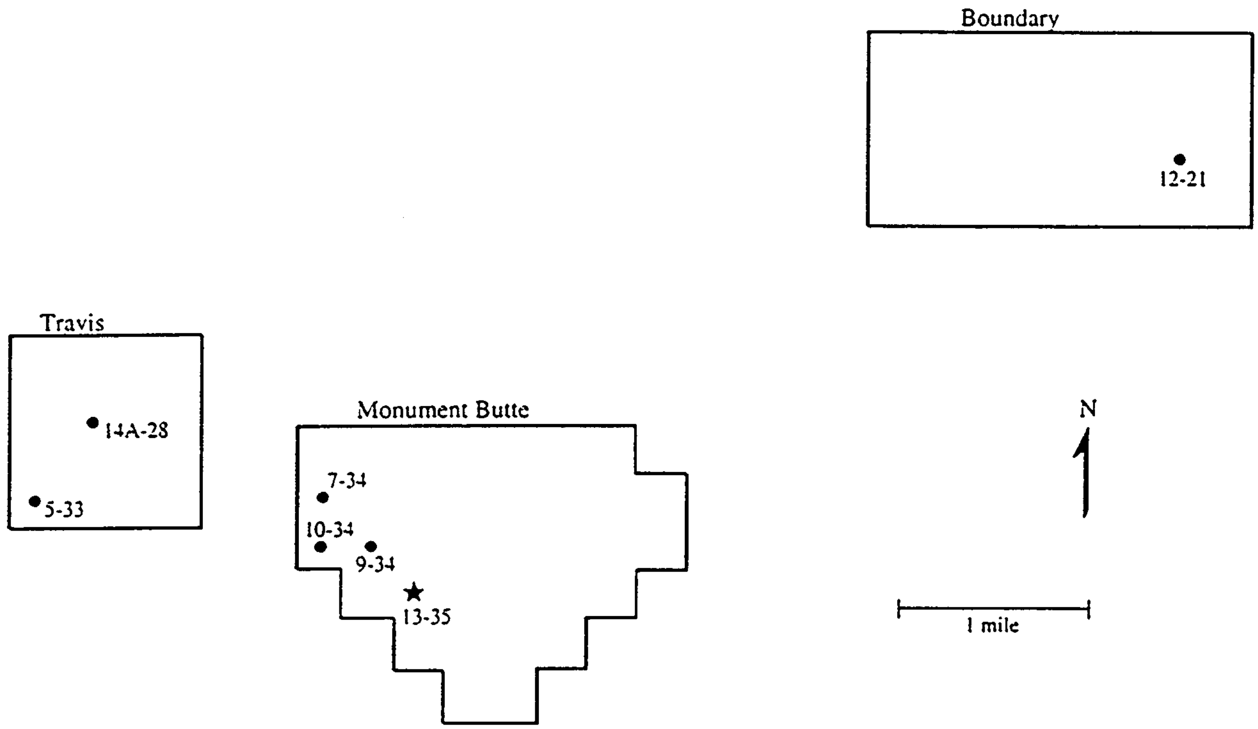


Figure 3-6. Locations of wells drilled under the DOE program for which there is data from the Formation MicroImager log.

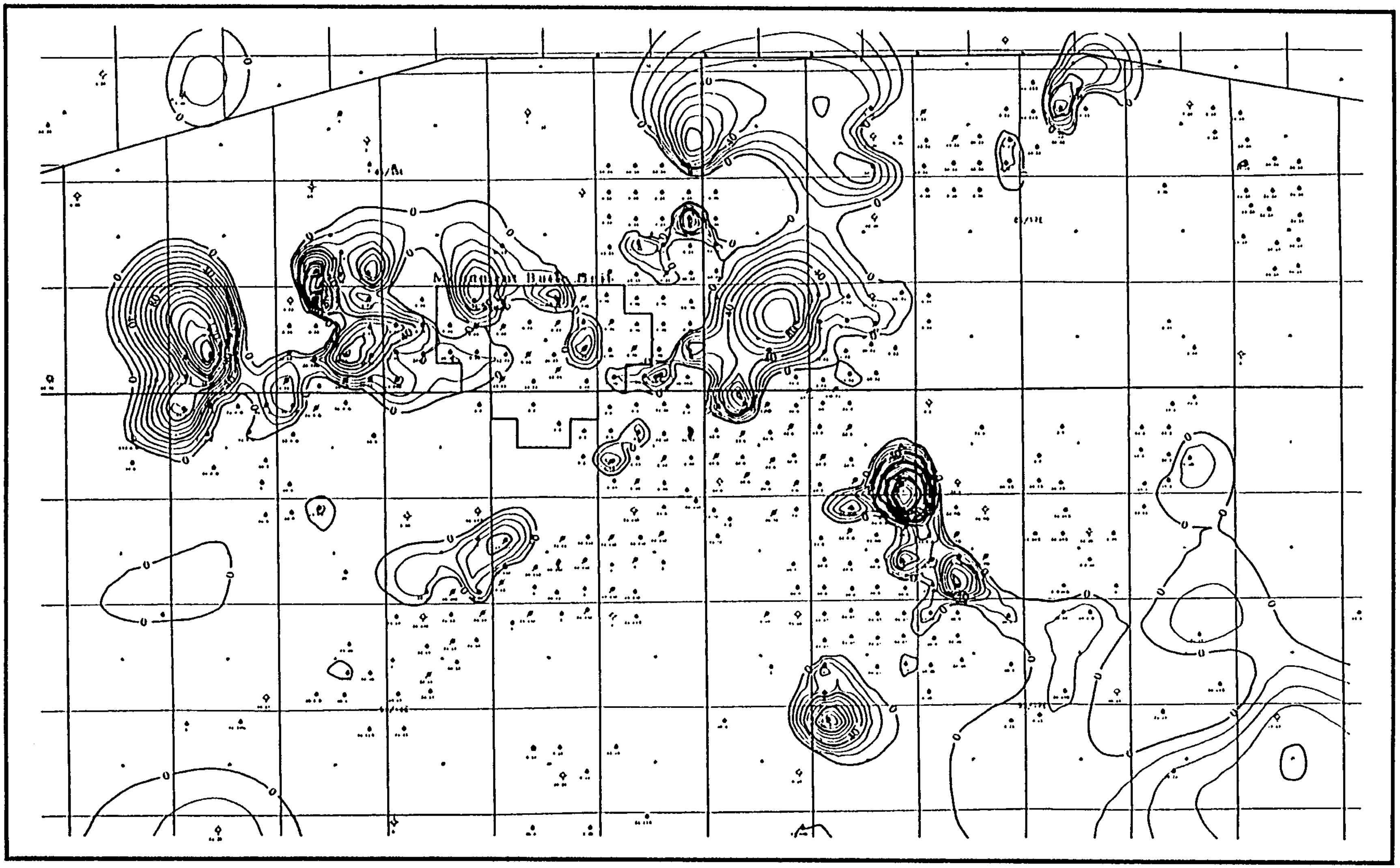


Figure 3-7. Net sandstone isopach map of the Lower Douglas Creek sandstone in the Greater Monument Butte area

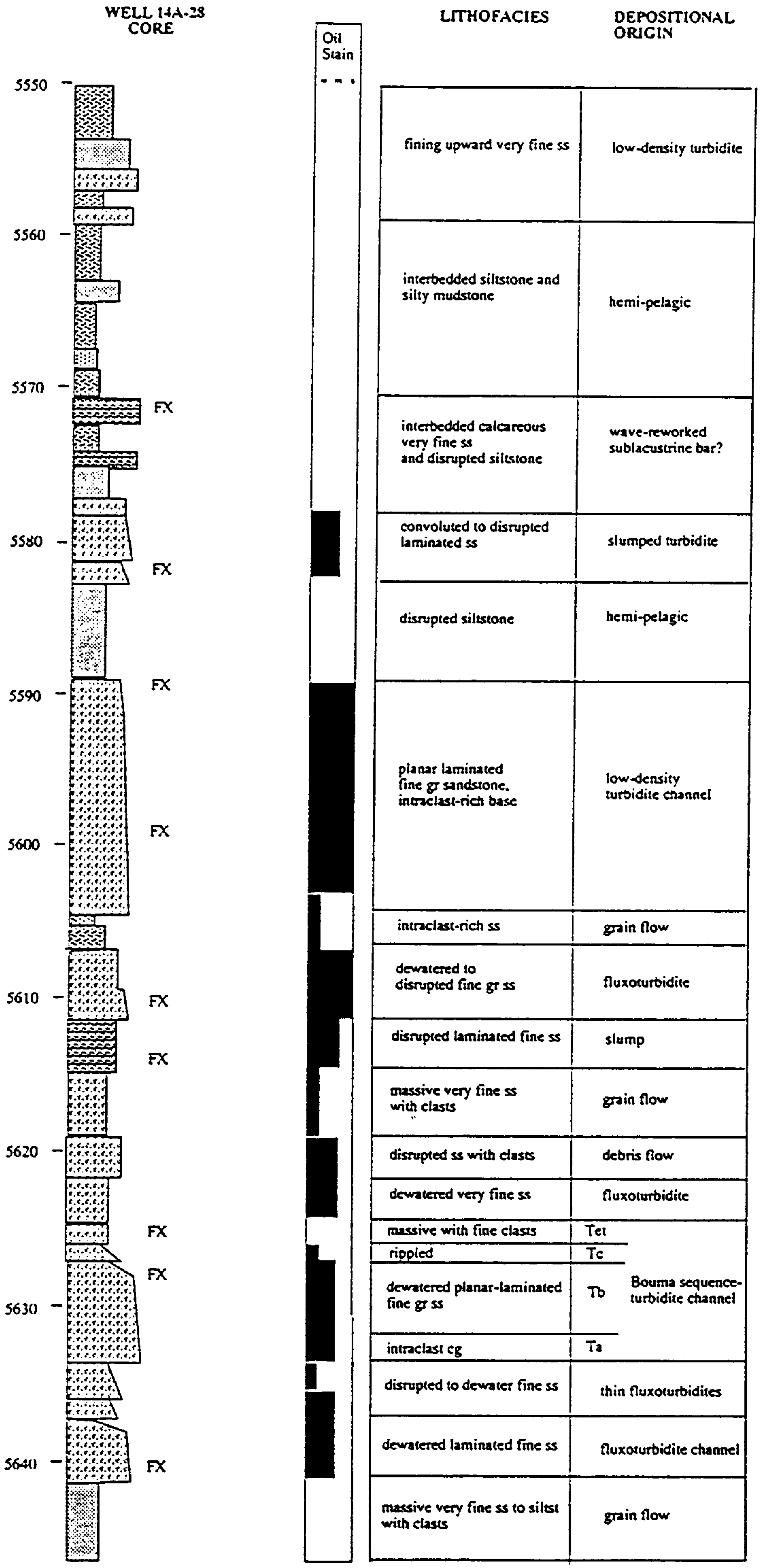


Figure 3-8. Summary of lithofacies and inferred depositional origin of Lower Douglas Creek sandstone in core from well Travis Federal #14A-28. (FX=Fracture)

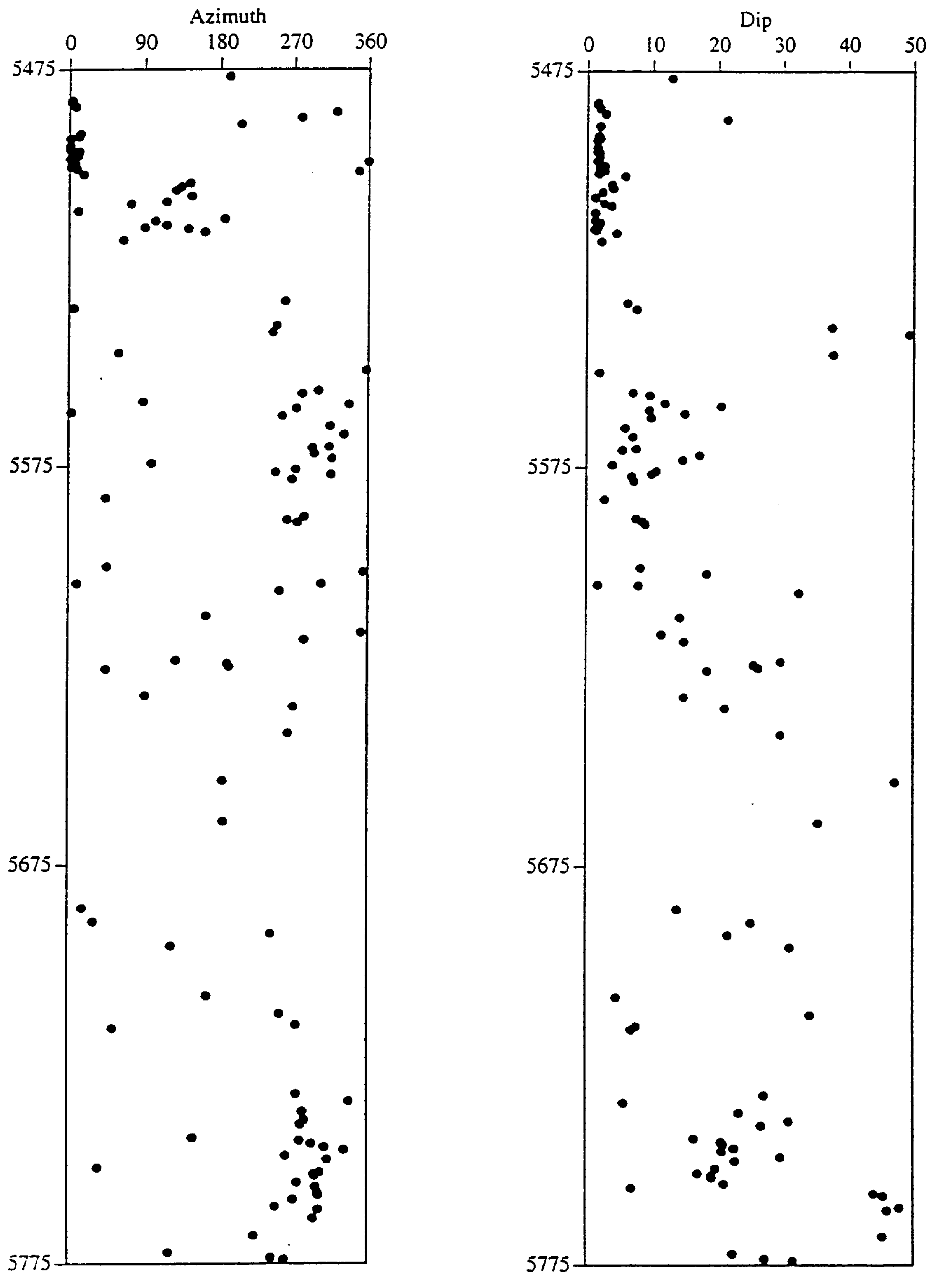


Figure 3-9. Dip angle and azimuth as function of depth interpreted from the FMI log in the Lower Douglas Creek interval in well Travis Federal #14A-28

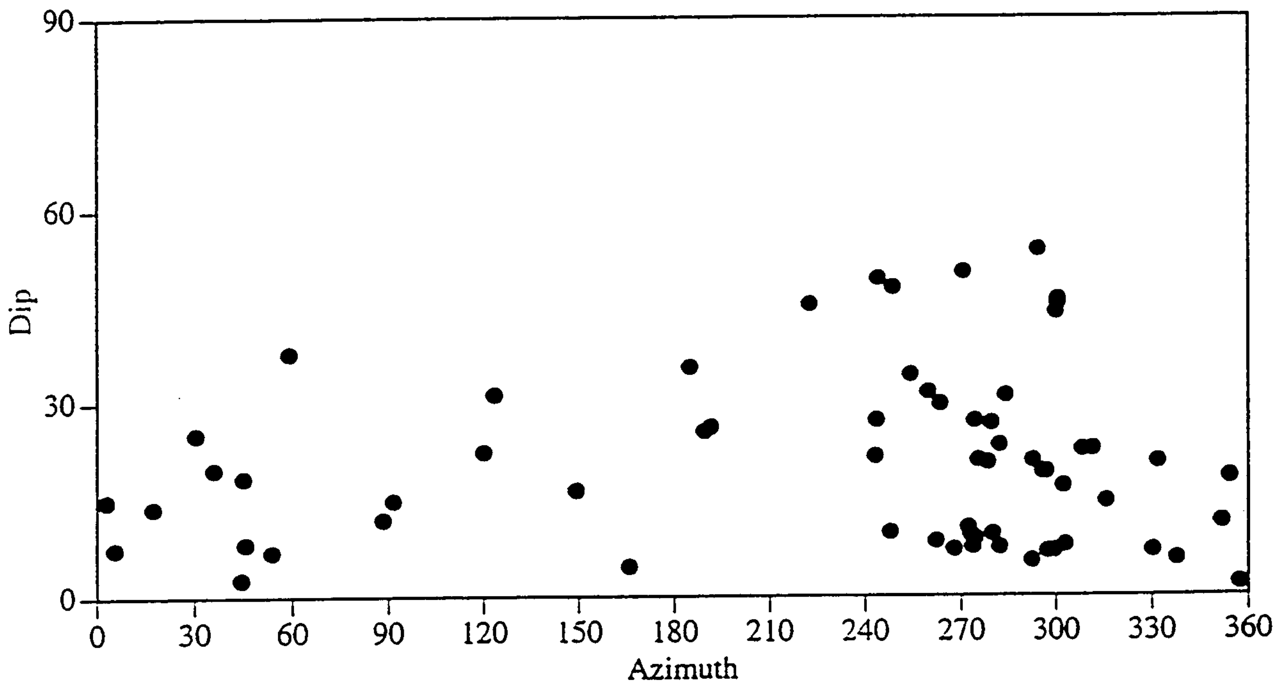


Figure 3-10. Dip versus azimuth (DVA) plot of bedding from the Lower Douglas Creek from 5538 ft to 5775 ft in Travis Fedearl #14A-28

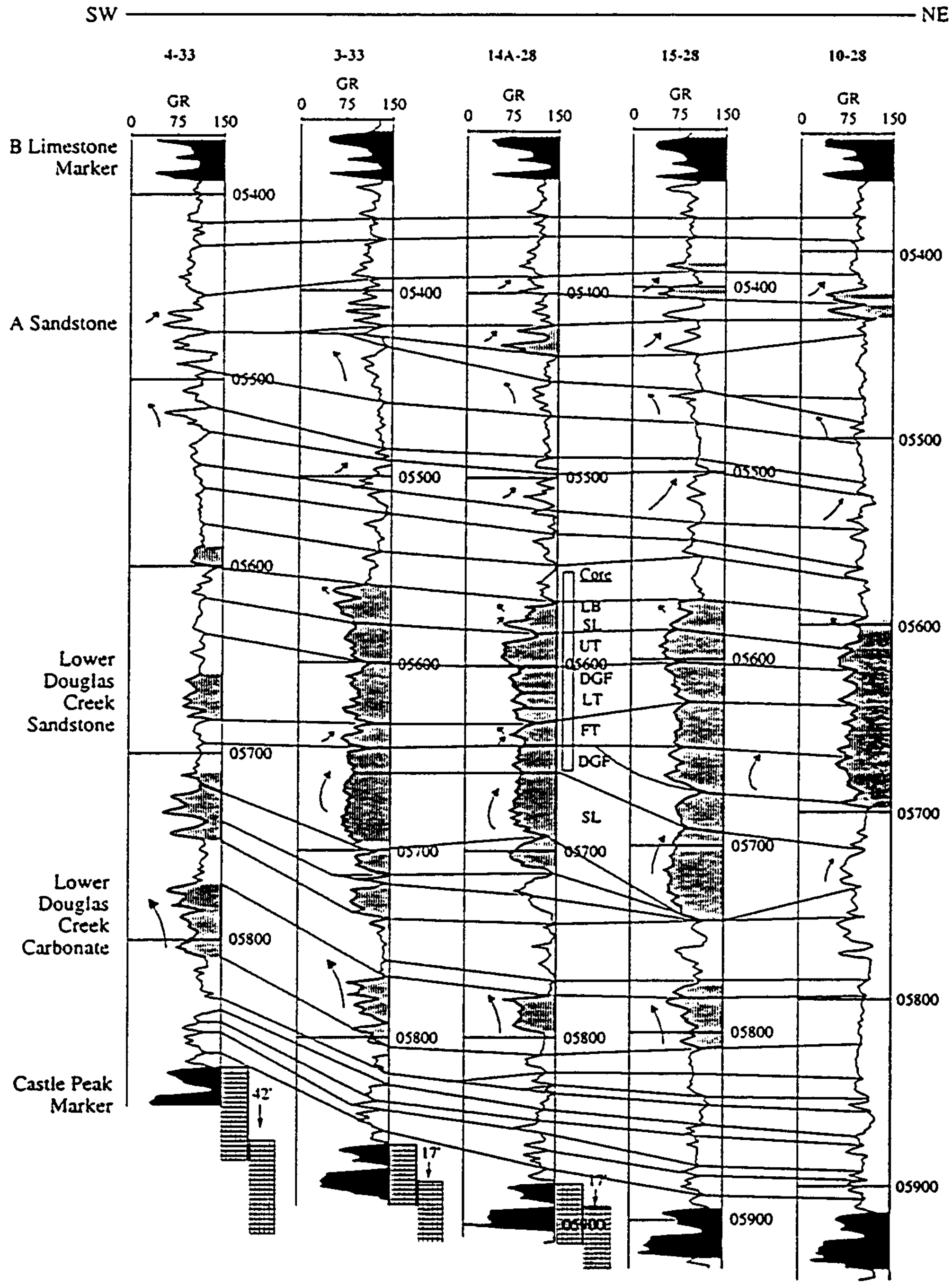


Figure 3-11. Correlated well logs of Lower Douglas Creek sandstone in the Travis unit. Channelized sands show a general fining-upward pattern (arrows to right). Wave worked sublacustrine bars coarsen upward (arrows to left). SL=slump, FT=fluxoturbidite, DGF=debris and grain flows, UT=upper turbidite, LB=lacustrine bar

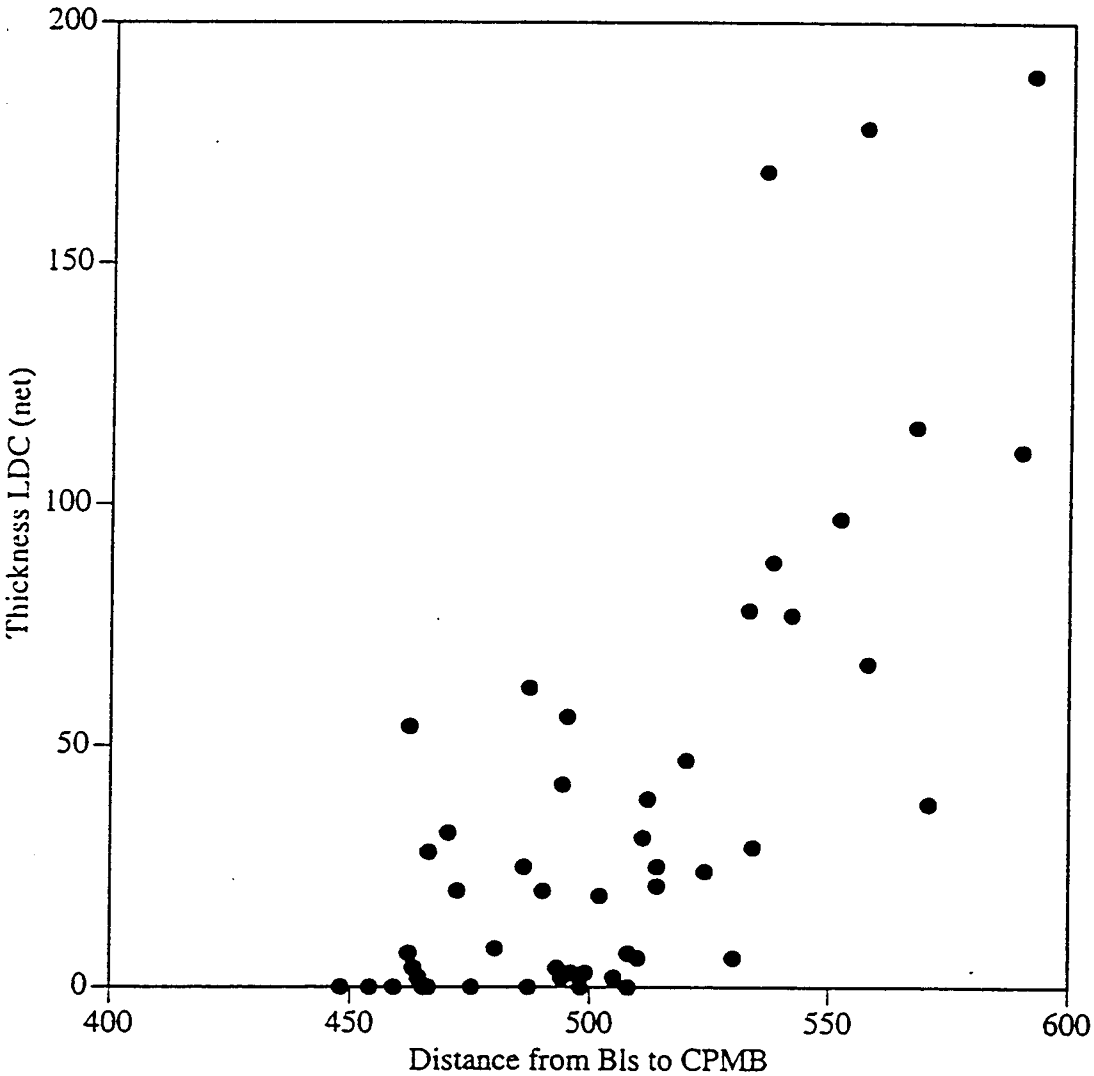


Figure 3-12. Cross plot of Lower Douglas Creek net sandstone thickness versus distance between the B Limestone and the Castle Peak marker beds

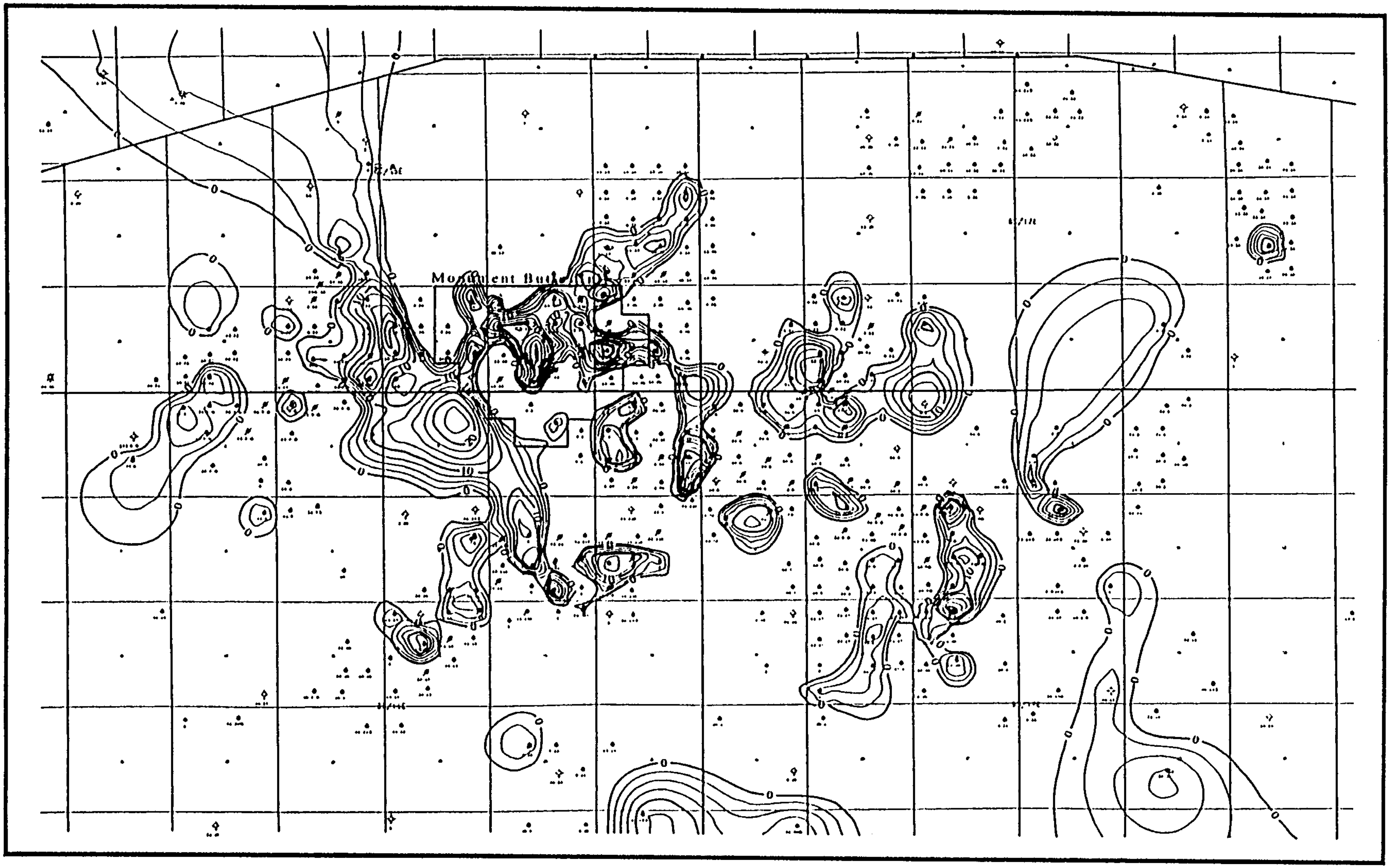


Figure 3-13. Net isopach sandstone map of the B2 reservoir

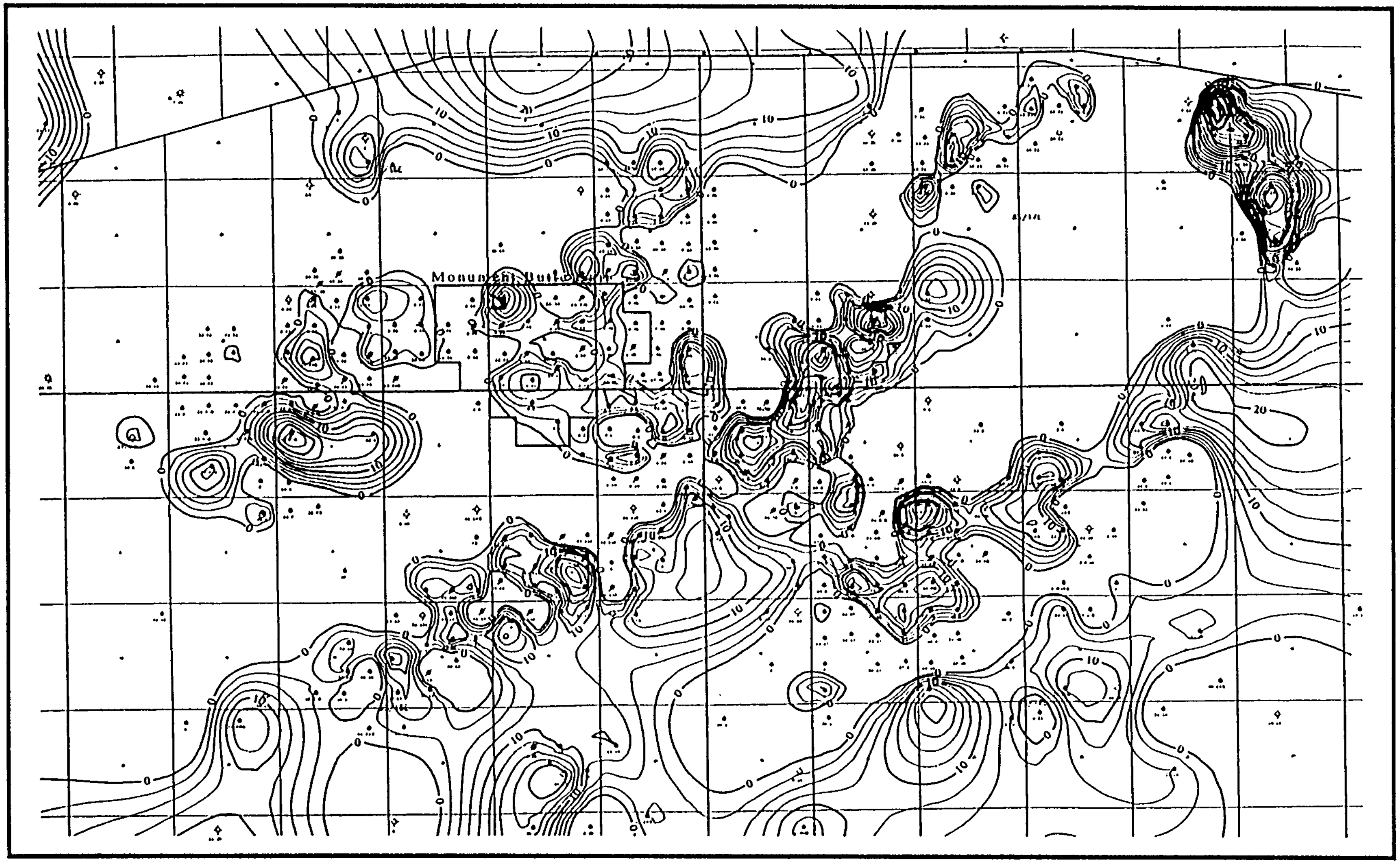


Figure 3-14. Net isopach sandstone map of the C reservoir

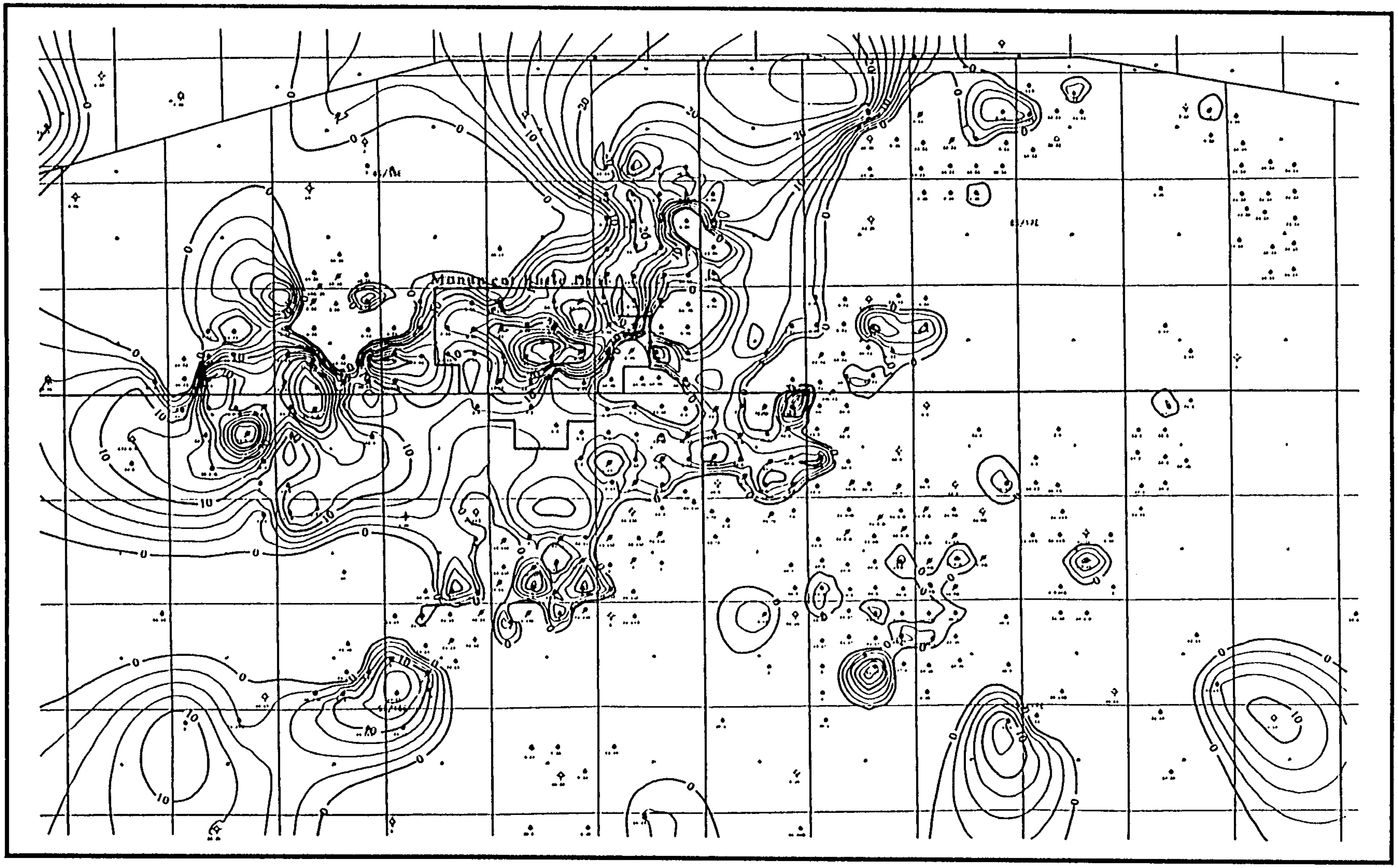


Figure 3-15. Net isopach sandstone map of the D1 reservoir

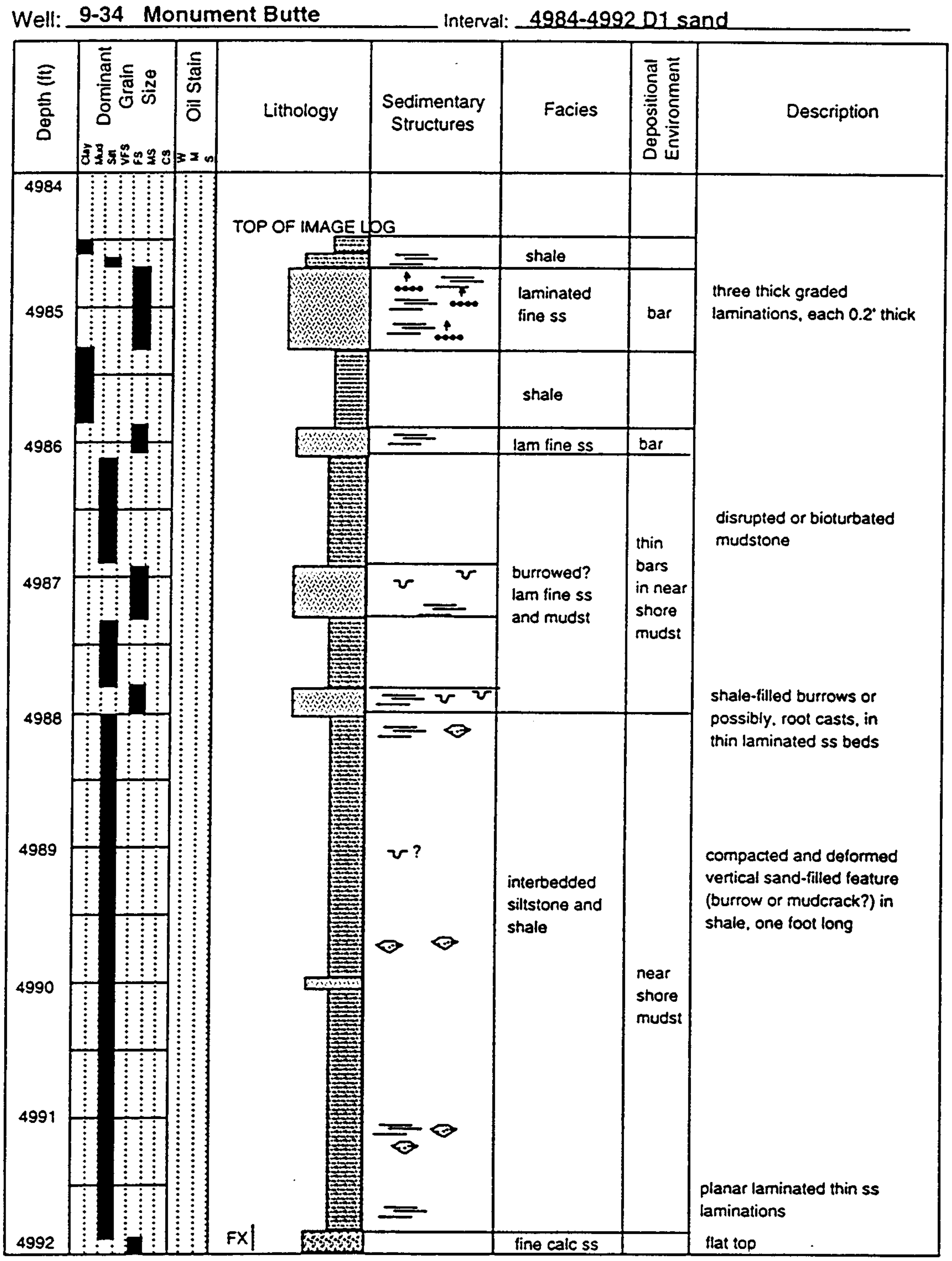


Figure 3-16. Lithologic log of the D1 reservoir interpreted from the FMI images from Monument Butte Federal #9-34

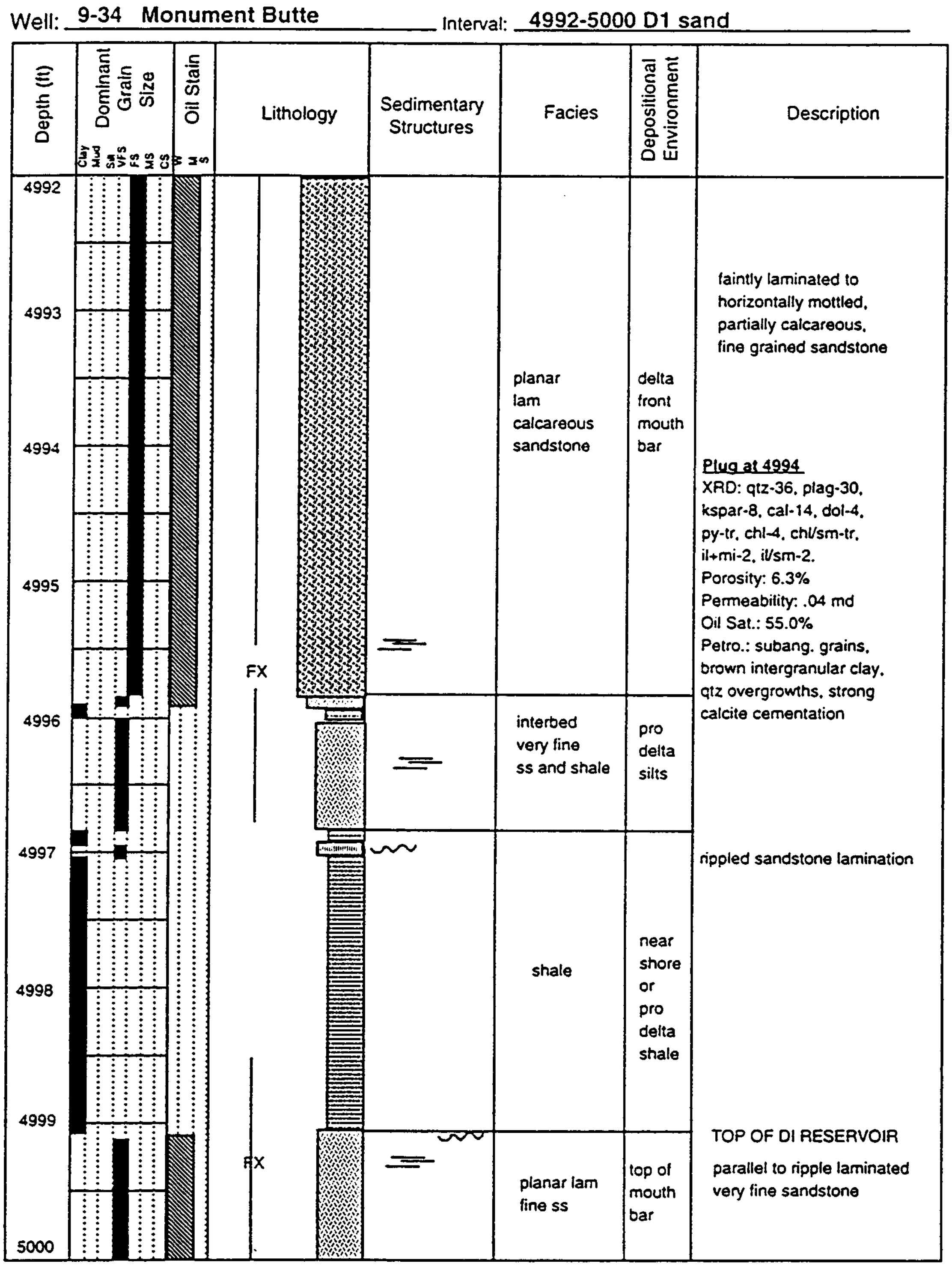


Figure 3-16 continued

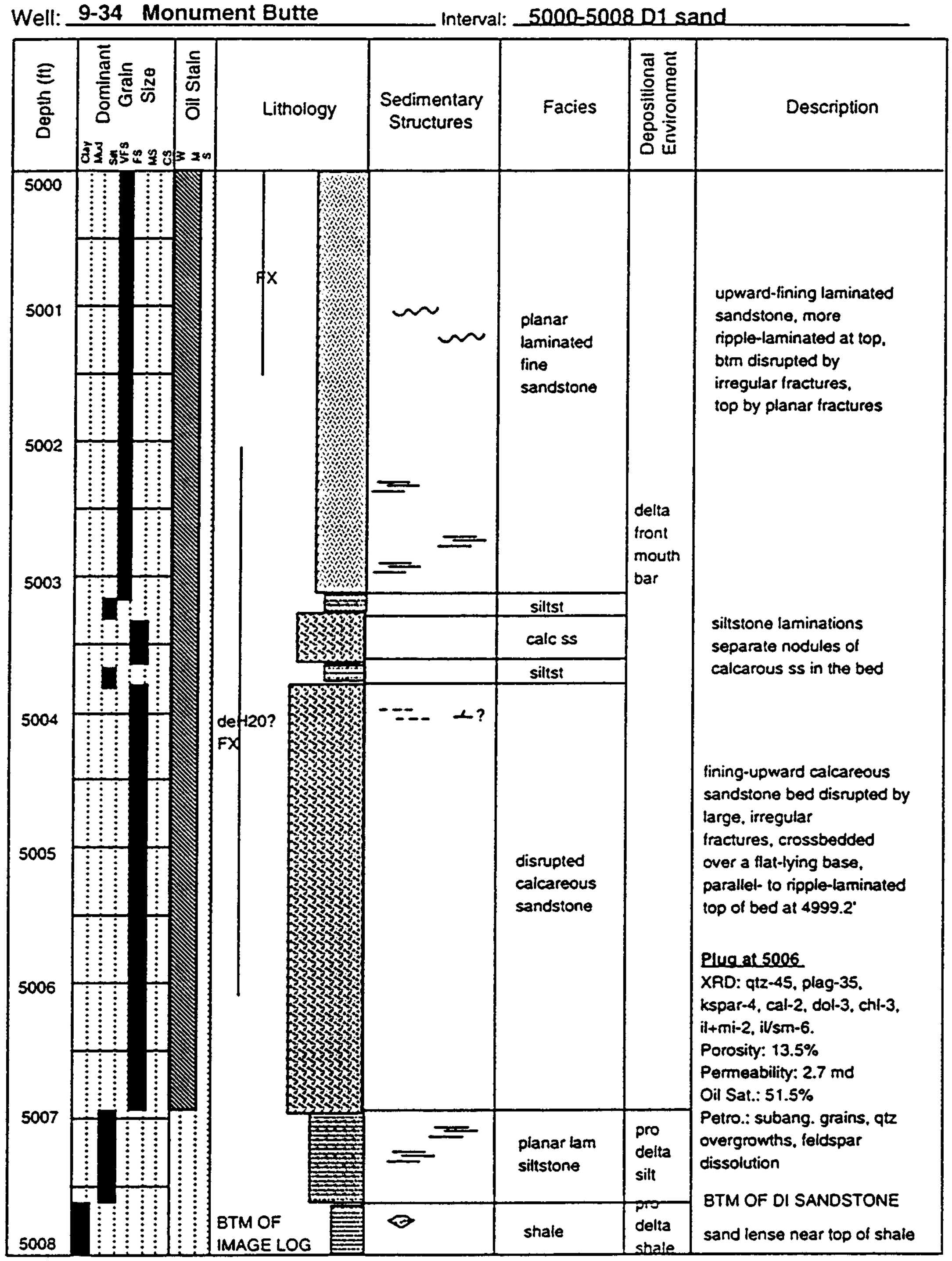


Figure 3-16. Continued

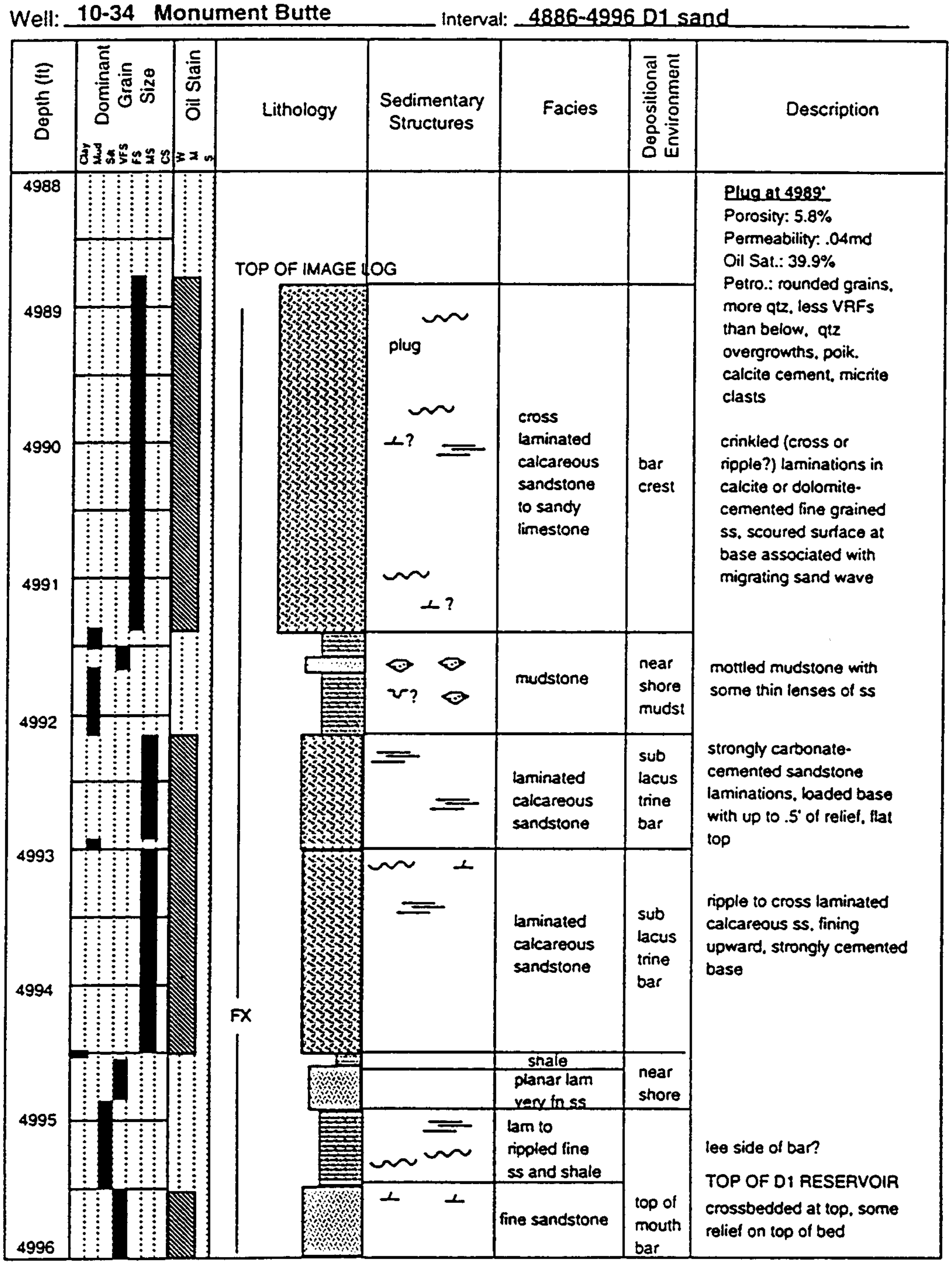


Figure 3-17. Lithologic log of the D1 reservoir interpreted from the FMI image from well Monument Federal #10-34

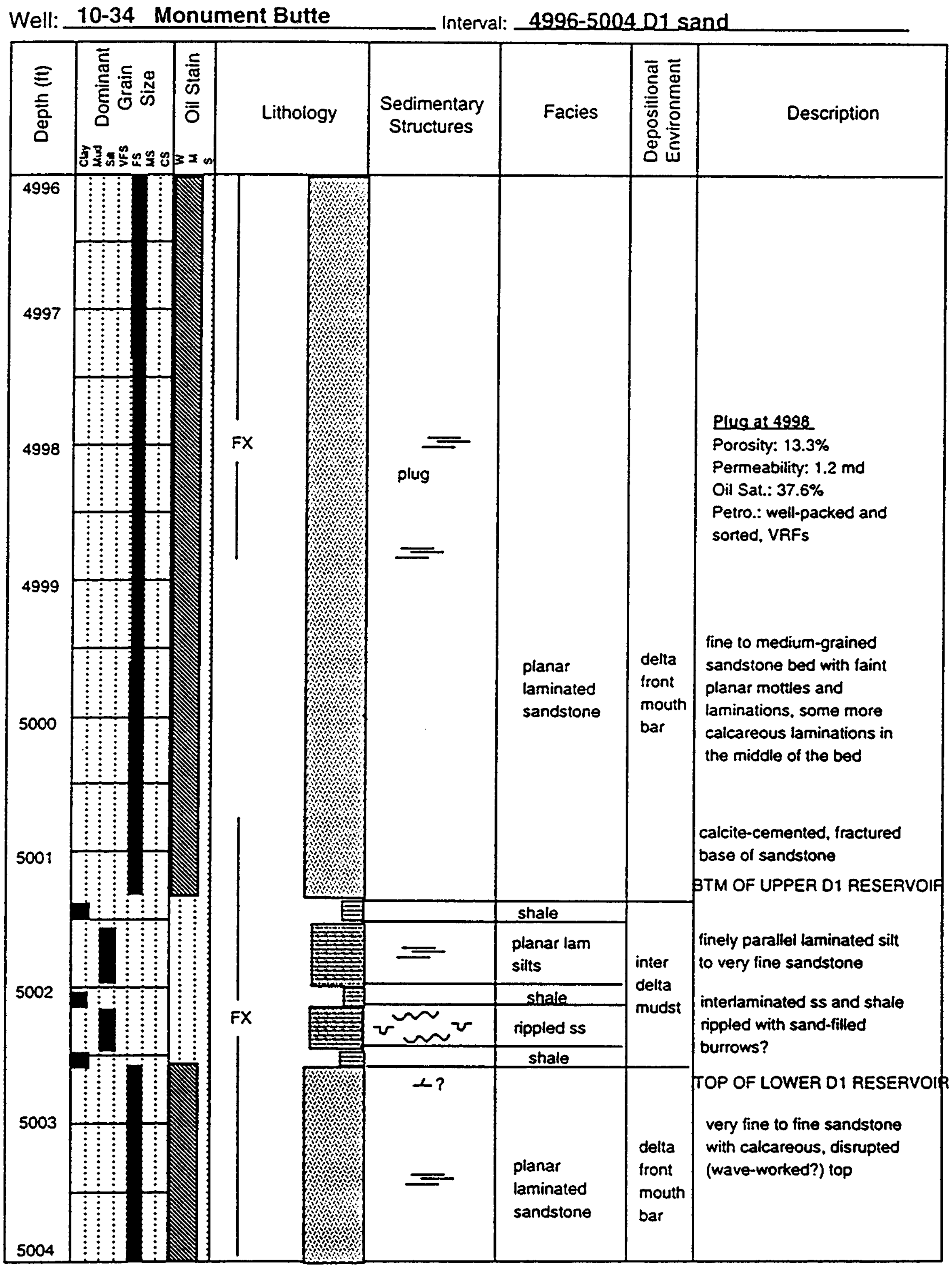


Figure 3-17. Continued

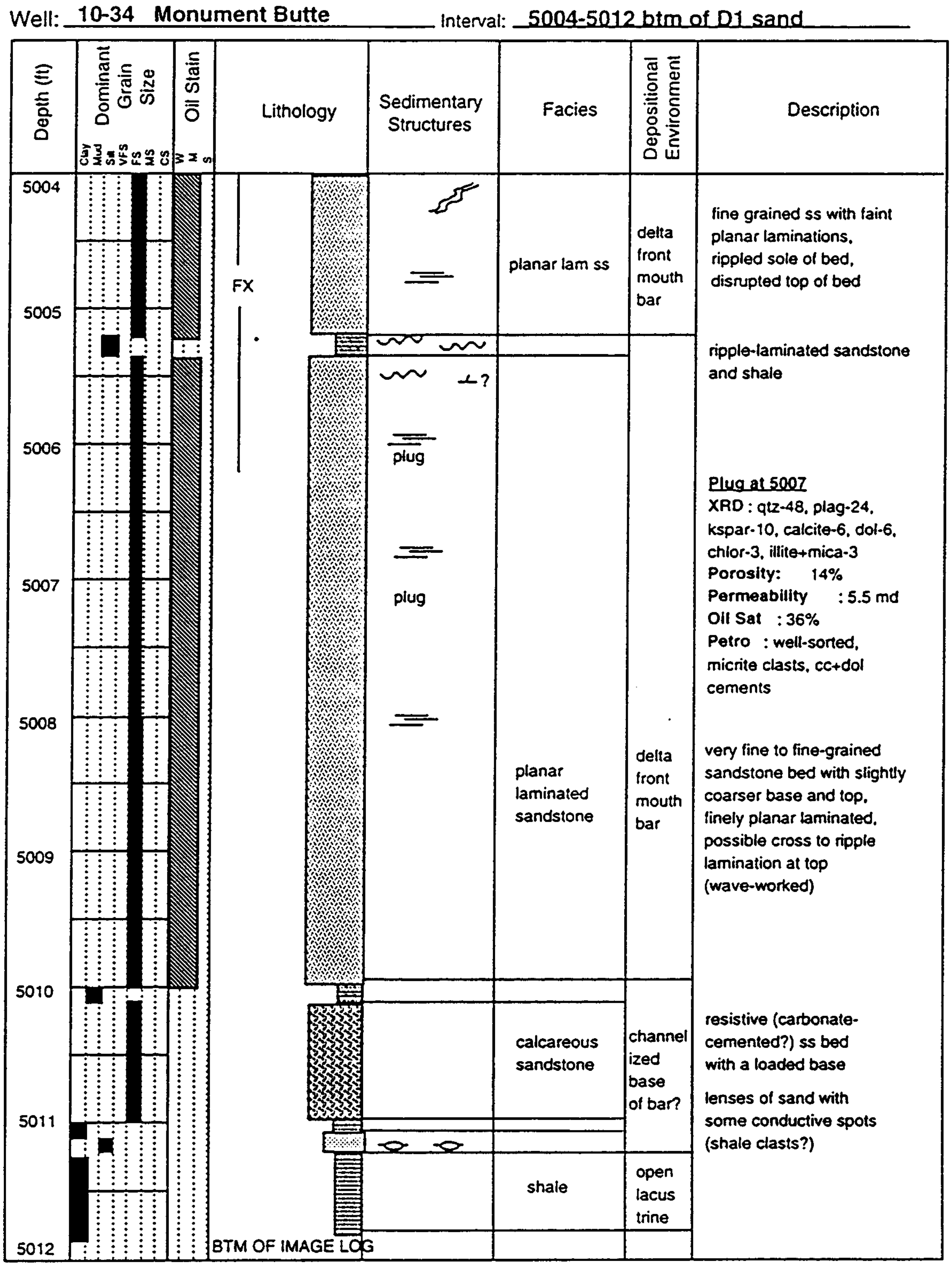


Figure 3-17. Continued

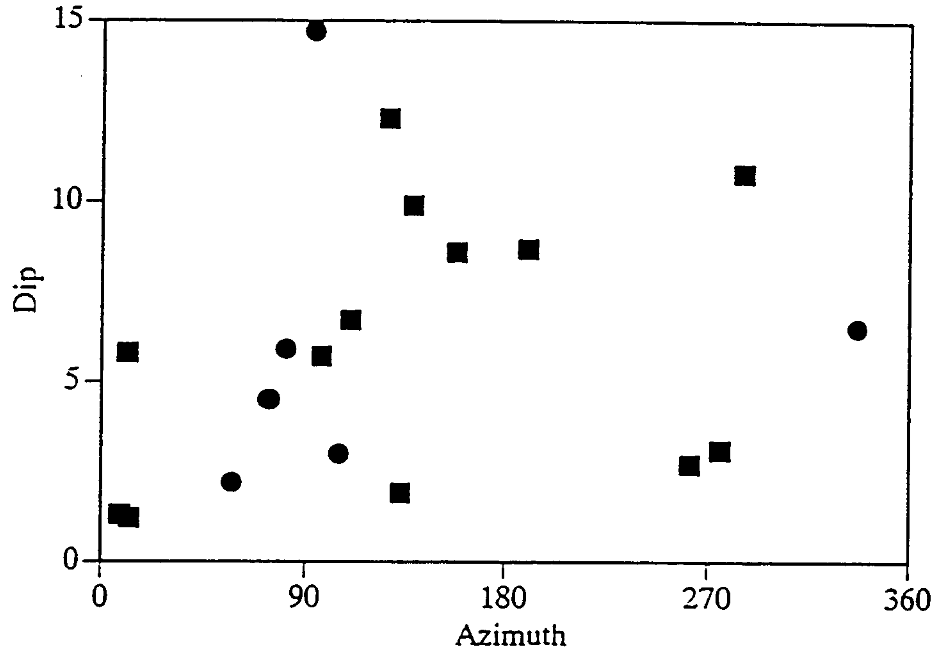


Figure 3-18. Dip versus azimuth (DVA) plot of bed orientation from the D1 reservoir in wells Monument Butte Federal #9-34 (squares) and #10-34 (circles)

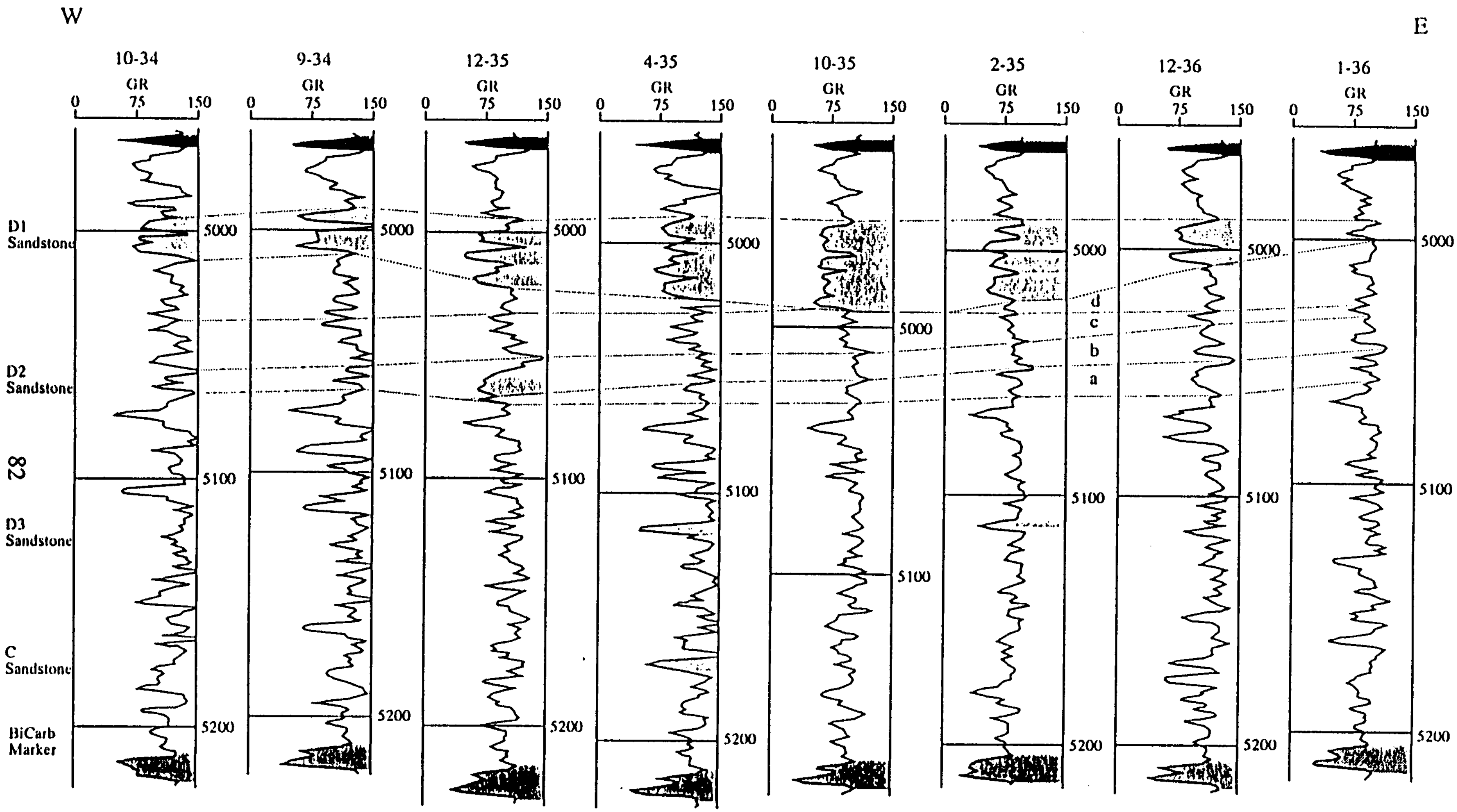


Figure 3-19. Correlated well logs of the D sandstone interval in the Monument Butte unit. The D1 sands consist of sublacustrine bars, separated by thin shales. The underlying packages of rock, labelled a, b and c, downlap in a lakeward-stepping pattern. The d beds and the D1 sands are vertically stacked in an aggradational pattern.

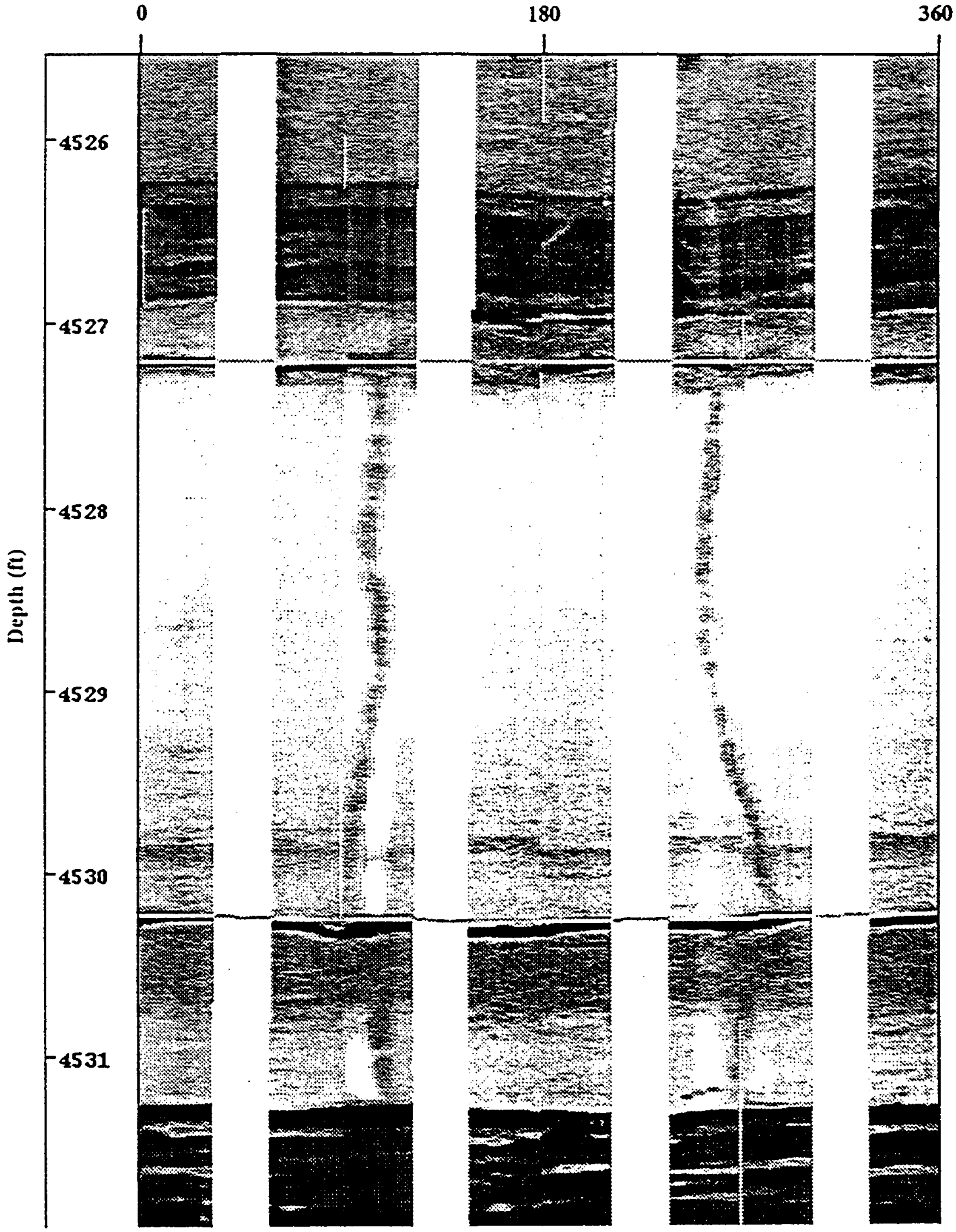


Figure 3-20. FMI image of a stratigraphically bound fracture from Travis Federal #5-33.

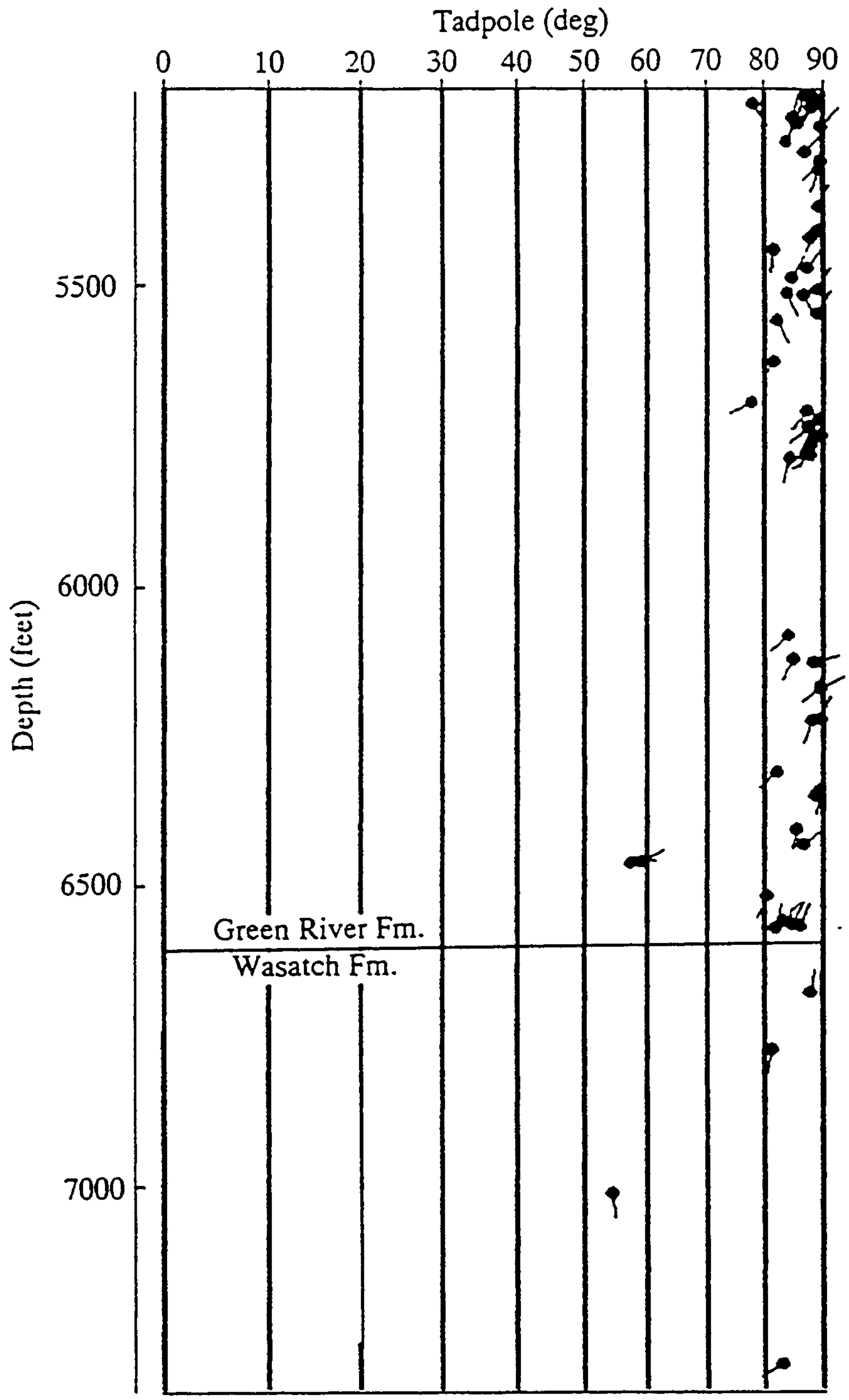


Figure 3-21. Tadpole plot of orientation of fractures imaged by the FMI log in Boundary Federal #12-21. The depth of contact between the Green River and the Wasatch Formations is shown.

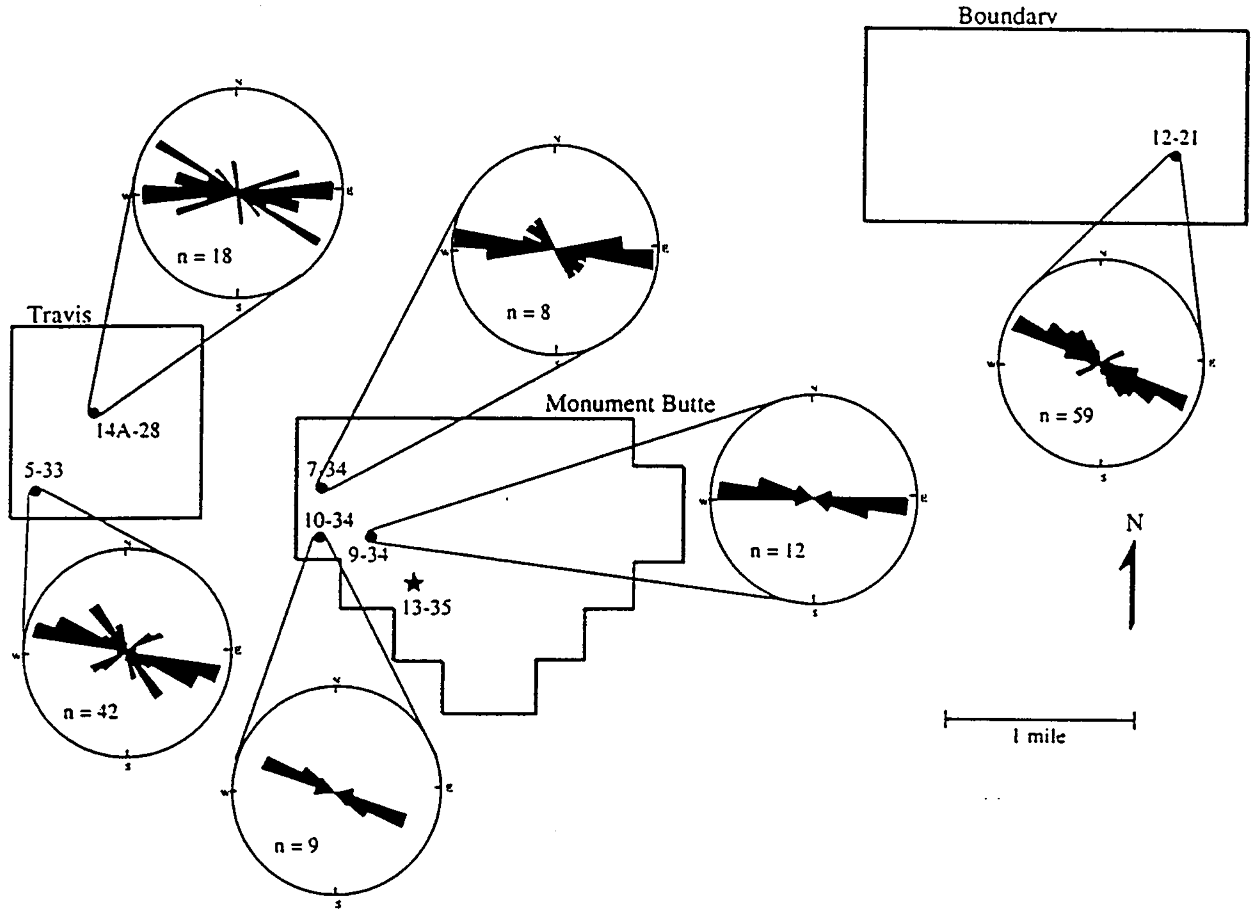


Figure 3-22. Rose diagrams showing the orientation of fractures imaged by the FMI log in the Greater Monument Butte oil field. Data shows the orientation of 140 fractures. Well #13-35 is the type log for the project.

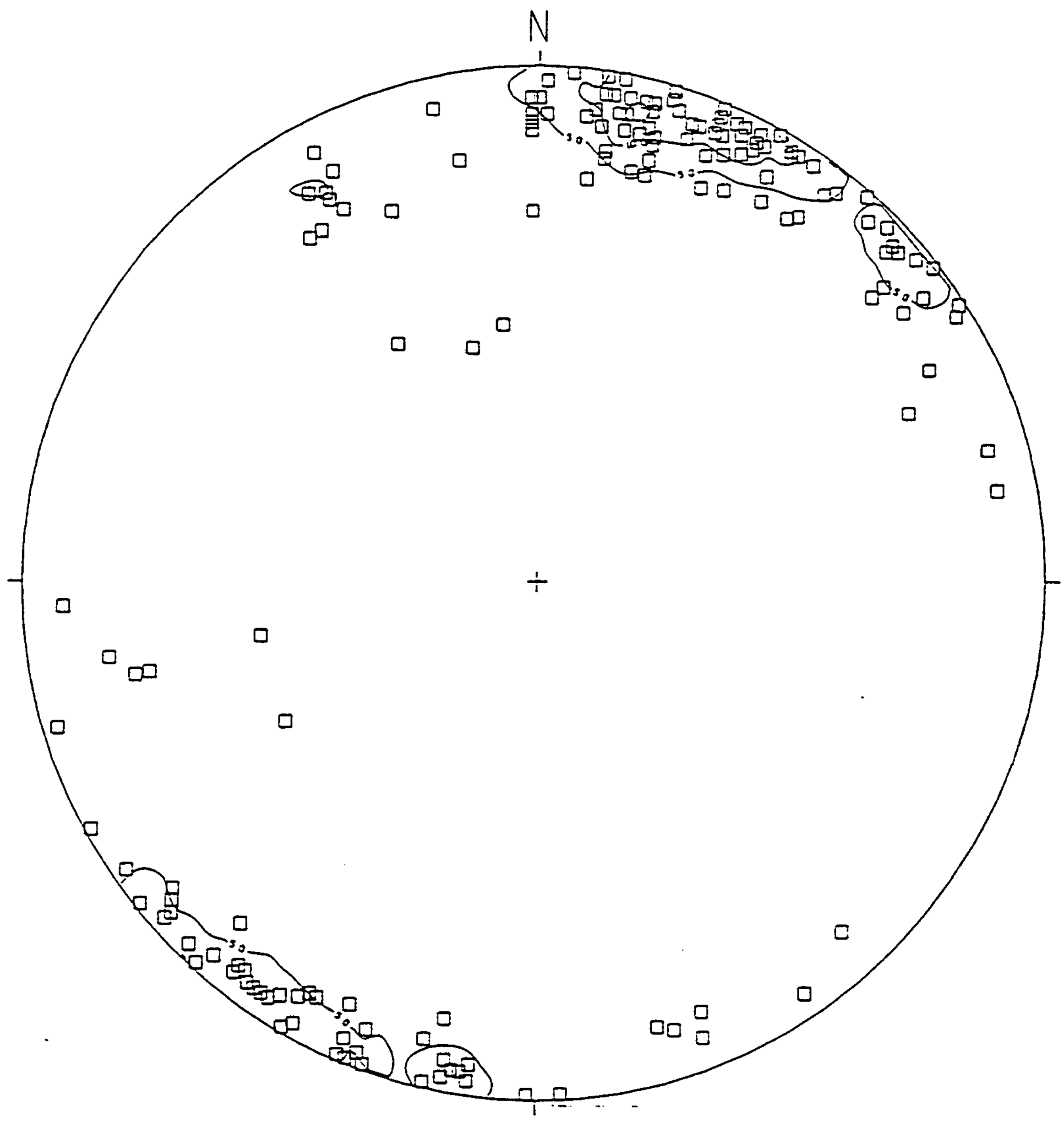


Figure 3-23. Equal angle projections of fractures imaged by the FMI in the Greater Monument Butte field. Contours at 5% and 10%. 165 samples.

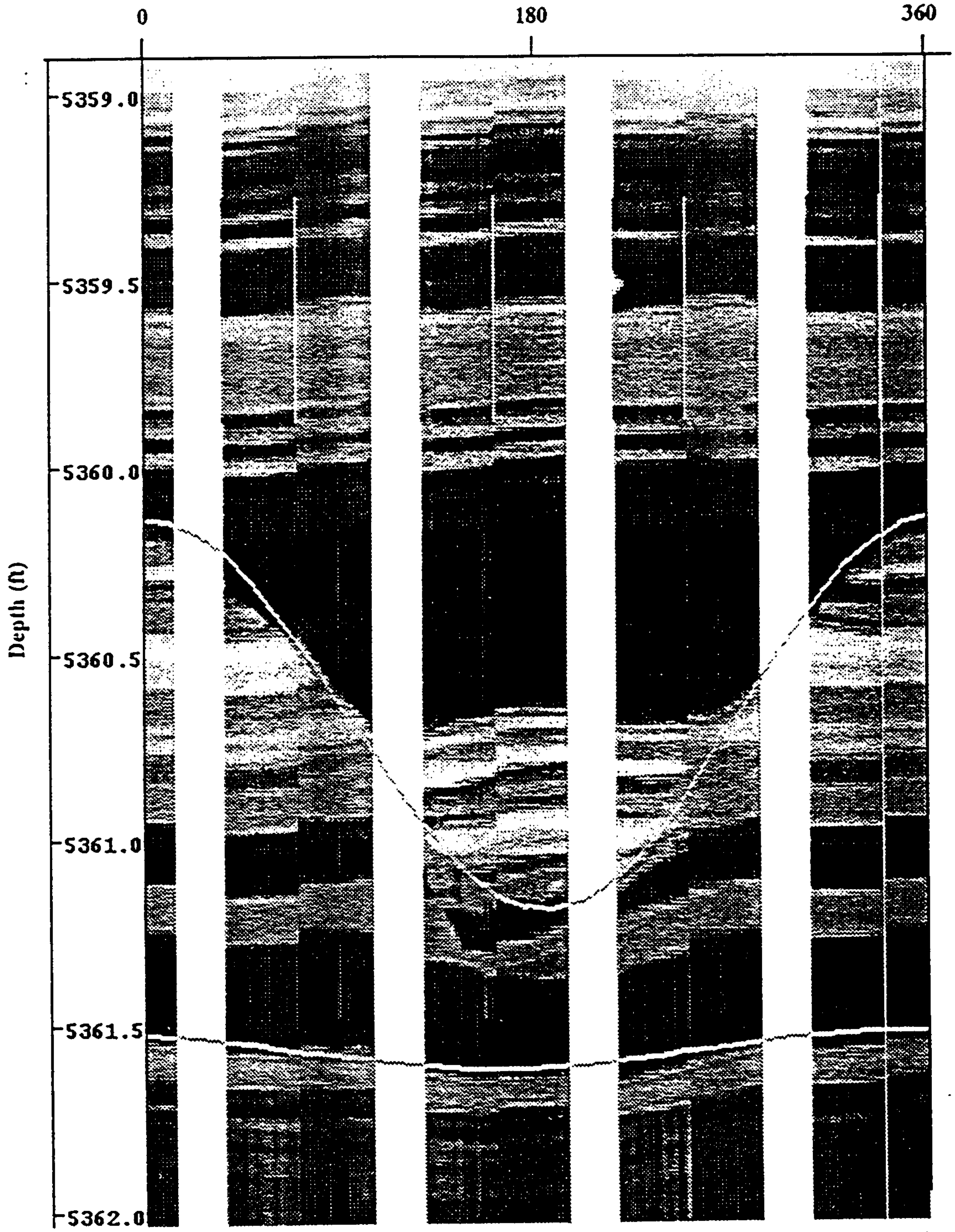


Figure 3-24. FMI image of a minor fault in well Travis Federal #5-33.

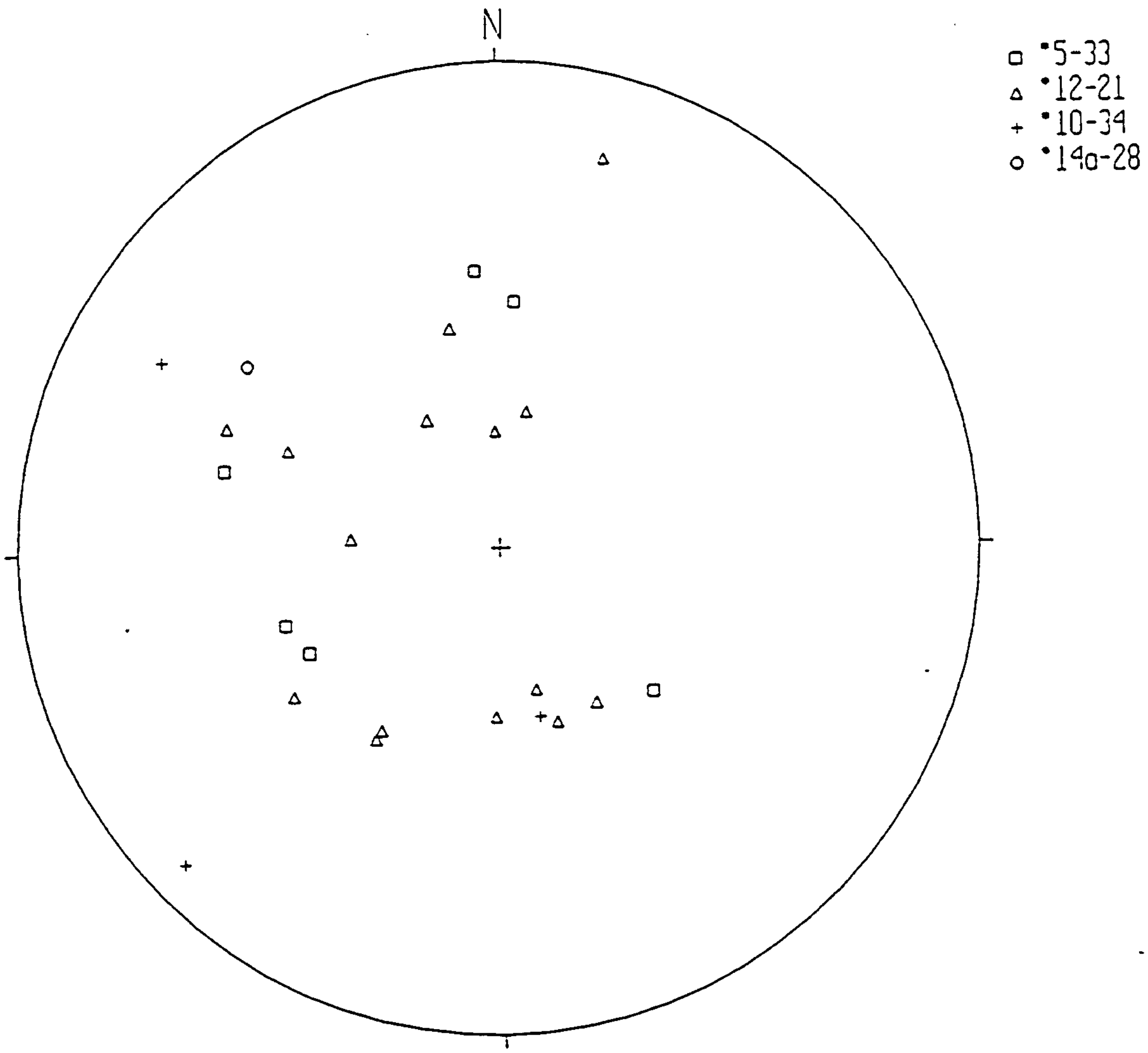


Figure 3-25. Equal angle projection of poles to minor faults measured by FMI logs in the Greater Monument Butte area

Chapter 4. Reservoir Simulation

Objectives and Approach

The preliminary objective of the reservoir simulation study was to develop a history match of the oil production from the Monument Butte unit. It was believed that this in turn, would provide credible evidence that the underlying production mechanisms were well captured by the model. The reservoir model could then be used for production forecasting. Initially, only the reservoir sands within the Monument Butte unit were modeled and the oil and gas production performance was matched unit-wide and on a well by well basis (U. S. DOE, 1994; Deo, et al., 1994).

As the unit expansion continued, it became evident that the multiple reservoir bodies within the Monument Butte unit extended well beyond the unit. At this time, the original model was expanded to include additional 80-acre strips on all four sides. In order to visually depict the basic mechanisms of solution gas drive and gas evolution during primary production, and reservoir pressurization and gas redissolution during secondary production, the time-dependent output data from the model was animated to create a video movie. The movie clearly showed which regions of the reservoir depleted first, which got pressurized and pockets of oil that was bypassed.

Geologic and production analyses of the nearby Wellsdraw and Jonah units, which were placed on water floods after the success of the Monument Butte unit water flood, showed that there was some degree of connectivity between sand bodies in these units. The question then was, what was the appropriate scale for representing and simulating these sand bodies ? In order to answer this question, a 12-section area surrounding the Monument Butte unit was considered. First, the logs for about 200 wells in the region were digitized and geostatistical modeling was performed to generate reservoir images. Even though five to six sand bodies contribute to production in a typical well in the region, only D1 and B2 reservoirs were simulated, since water flood in the Monument Butte unit targeted only these two sand bodies. Results of the geostatistical simulations and flow simulations using resulting reservoir images are presented in this report.

Introduction

In the Monument Butte region, it is common to produce oil from four to five (sometimes as many as twenty) productive sands typically arranged in a distinct layered format. The reservoirs in these sand units can be considered, for modeling purposes as distinct. Most of the reservoirs are undersaturated with the initial reservoir pressure close to the initial bubble point pressure. As a result, the gas oil ratios (GORs) increased precipitously a few weeks into the primary production process. The increased gas production slowed the oil production significantly causing low primary recovery. Had water flood not been implemented at this stage, the unit would not have been economically viable. A unique water flood strategy was implemented to revitalize the unit wherein the largest producers were converted to injectors. In keeping with the lacustrine depositional environment, fresh water was injected into the formation. The water flood strategy was successful and the secondary production from the unit has already exceeded the primary production.

A comprehensive reservoir simulation and history matching effort was undertaken to understand the production mechanisms underway in MBU. The results were published in an earlier paper (Deo, et al., 1994). In this study, thicknesses of the reservoir sands were assigned using geologic isopachs and knowledge about perforated intervals. Thicknesses of internal grid blocks (where data was not available) were determined by conventional interpolation methods. The model area consisted of the unit with an additional 40-acre margin on each side. The geologic heterogeneity in the MBU was represented only through varying sand thicknesses. A thickness-weighted average porosity was assigned to each sand unit. For history matching purposes, permeabilities of well-containing grid blocks were adjusted until reasonable responses were obtained for the overall oil and gas production from the unit. All the wells in the unit and in the region in general, are hydraulically fractured and thus the near well bore permeabilities are markedly different from measured core permeabilities. The above approach yielded excellent history match with the field data, unit-wide as well as for most individual wells. The exercise also revealed that the reservoir performance in primary and secondary recovery closely resembled that of a undersaturated reservoir close to its initial bubble point pressure. The model also established that about 30% of the injected water migrated outside the unit boundaries.

The objectives of this study were the following:

1. To use all of the available data (mostly in the form of digitized logs) to generate geostatistical reservoir images of all relevant reservoir properties; thicknesses, porosities-permeabilities and water saturation.
2. To study the production performance of the Monument Butte unit in isolation and as a subset in a large 12-section area.
3. To combine the different reservoir property data sets and generate multiple realizations.
4. And to examine the resulting variability in primary and secondary production response for the unit and for the 12-section area.

A map of the 12-section area is shown in Figure 4-1. This area partially includes two other large water floods in the region. In this report, geostatistical analyses of two of the most productive sands from the unit (D1 and B2) and reservoir simulations of the D1-reservoir have been presented.

Geostatistical Modeling

The greatest advantage of geostatistical simulations is that the calculations provide equally probable reservoir images based on the data at known control points (wells). These realizations, in turn, give statistical variability in parameters such as initial oil and gas in place, etc. When different realizations from geostatistics are used in flow simulations, statistical variability in production can be obtained.

Data Employed

Usually the first step in generating a geologic model of a reservoir is distribution of different facies or rock types (Hand et al., 1994; Begg et al., 1994). Next, the distributions of lithotypes or sands are determined in individual facies, followed by porosities, permeabilities etc. Data on facies or lithotype distributions were not available for this study area. For each of the wells in the 12-section area, log data were available at 2 feet resolution. Porosity and water saturation values were calculated from the log data. Different sand intervals and thus thickness of the sands were identified in each well based on high porosity and low water saturation values. Approximately, 65 cores were obtained from some of the wells in the region. Air permeabilities were measured from these cores. Measured core permeabilities (horizontal direction) were in the 0.01-50 md range. Vertical permeability data were not available. A crossplot of permeability versus porosity was also available. The porosity-permeability crossplot is shown in Figure 4-2. The crossplot correlation was generated using data from a number of sands in the region. For the purpose of this study, it was assumed that the crossplot correlation was true for the D1 and the B2-sands.

The data were used to obtain distributions of thickness, porosity and saturations using geostatistical principles. In the absence of the facies data, individual sands were distributed through sand thickness as the first step. Once sand thickness and thus sands were distributed throughout the study area, porosities and water saturations were distributed independent of each other.

Methodology

Principles of sequential Gaussian simulations were used to obtain distributions of different properties. The SGSIM algorithm developed by Deutch and Journel (1992) was used to perform the simulations. The algorithm requires the data to be normally distributed. The data sets for each of the above mentioned attributes were transformed to obtain normal distributions. After the simulations they were transformed back to their original values. Following sections give information on individual properties.

Thickness

A horizontal variogram determined for the sand thicknesses was omni-directional. A model was obtained for this variogram. The variogram model had two components, one of which was spherical with a correlation length of 2000 feet and the other exponential with a correlation length of 4000 feet. The model for B2-sands was also omni-directional but had only a spherical component with a correlation length of 1450 feet. Both the D1 and B2 sands models did not show any nugget effect. The details of the models are given in Tables 4-1 to 4-4. The distribution of D1 and the B2 sand thicknesses in the 12-section model (one of the realizations) are shown in Figures 4-3 and 4-4. The sinuous nature of the reservoir is captured by these images.

Porosity and water saturation

Variograms were calculated to find spatial variability in the vertical and the horizontal directions. The vertical coordinates were normalized to obtain a uniform coordinate system, as the thickness of the sands varied from well to well. An average thickness was calculated. The thickness in each well was converted to the average thickness and the vertical coordinates were transformed accordingly. A vertical variogram was calculated for these converted coordinates. A horizontal variogram was also calculated from all the available data values. These horizontal variograms were also omni-directional. Just like the thickness variogram, both the horizontal and vertical variograms were modeled by nested structures.

The correlation lengths for thickness and porosities were greater than the average well spacing of 1320 feet. For water saturations the first part of the model had a range of about 1200 feet, but the second structure showed correlation length greater than the average well spacing. Horizontal permeabilities were calculated from the simulated porosity values and the porosity-permeability cross-plot. The values of the permeabilities were constrained between 0.01-50 md, because the measured core permeabilities varied between those limits. The vertical permeabilities were assumed to be 50% of the horizontal permeability values.

The distributions of porosity, permeability and water saturations in the twelve section area are shown in Figures 4-5, 4-6 and 4-7 for the D1 sands. The porosity distribution for B2 sands is presented in Figure 4-8. Only one of the several realizations generated has been chosen for presentation. Two different types of grids were used for generating distributions. A 33X25X100 grid was used to generate data used for the analysis of fluids in place (grid block dimensions 660 ft. X 660 ft.), while a 17X13X100 grid was used to generate data sets for flow simulations (grid block dimensions 1320 ft. X 1320 ft.). The correlation lengths for all the properties were greater than the block dimensions.

Reservoir Simulation

Reservoir simulation results for the D1 sands are reported in this section. Geostatistical reservoir images for the unit and for the 12-section area were used as input in the black oil simulator IMEX, developed by Computer Modelling Group (CMG). The grid size was 17X13X5. This was a variable thickness, variable depth model. Each block was characterized by its own thickness, porosity, permeability and water saturation. For reservoir simulation purposes, geostatistical realizations were generated on a 17X13X100 grid. The vertical grid blocks were upscaled 1:20 using conventional single-phase upscaling algorithms. The reservoir properties (block thicknesses, porosities and water saturations) were generated independent of one another. Multiple realizations were generated and variation in initial fluids in place were calculated. Table 4-5 shows OOIP (original oil in place) and initial water in place statistics for the entire 12-section area and for the MBU for the D1-sands. Similar statistics for B2 are summarized in Table 4-6. As expected the variability is much greater for the 12-section area, where large portions are yet to be developed.

Two completely different realizations of individual properties were used in generating input data for reservoir flow simulations. In order to assess the effect of employing results of different realizations in reservoir simulation, only one or two of the property sets were changed. This resulted in a total of eight different input files for reservoir simulation. The data sets employed in each of the eight simulations are shown in Table 4-7. As explained previously, these data sets were generated on a larger grid and in general the models had more fluids in place than the smaller grid models (Table 4-8). Once again the statistical deviation for the well-defined MBU were much lower than that for the entire 12-section area.

Results of reservoir simulation using one of the generated realizations are discussed below. In D1-sands, the Monument Butte unit contained 10.3 MMstb of oil compared to a total of about 58 MMstb in the entire 12-section area. The average oil saturation in the unit was about 76% compared to 74% in the total area. The initial reservoir pressure was assumed to be 2500 psia based on a gradient of about 0.5 psi/ft. When the water flood was initiated in the unit in September of 1987, the average pressure in the unit had dropped to about 1400 psia compared to an average pressure of 2160 psia for the entire region. These numbers provide the extent of drawdown that the unit as a whole created with respect to the surrounding reservoir. The cumulative production from the unit was about 370 Mstb or about 3.5% of the original oil in place. The total primary production for the unit was about 420 Mstb and about two-third (281) to three-fourth (315) of this production is believed to be from the D sands. Thus, the model overpredicted primary production. The model results are still reasonably close to the field results considering that there are no adjustable parameters in the model. At the end of 1995, the model predicted a production of about 520 Mstb. The total production from the unit as of December 1995 was about 1.1 MMstb. The D-sand contribution is believed to be between 700 Mstb to 800 Mstb. Thus, the model underpredicted water flood performance significantly. The model does not take into account hydraulic fractures. The results obtained thus far indicate that it is very important to consider the effect of hydraulic fractures on production. A material balance on water does indicate that most of the water injected into the unit stays in the unit.

In order to assess the impact of the model scale on primary and secondary recovery performance, reservoir simulations of the 12-section area, where the unit was essentially a subset were compared to simulations of the unit with only additional 40-acre strips on all sides. The simulation data sets for this comparison were developed using identical geostatistical data sets. The results of the MBU primary and secondary production at smaller and larger scales are compared in Table 4-9. The reservoir performance is almost identical at both the scales considered. Based on the extent of sands and on field experience, it was believed that the model scale would have a larger impact than what was observed in the simulation study. Hydraulic fractures were not accounted for in the simulations. Thus, the overall low reservoir permeabilities may have contributed to the observation concerning the effect of model scale on primary and secondary production performance.

The variability in primary and secondary production observed using the abovementioned eight statistical realizations is summarized in Table 4-10 for the Monument Butte Unit. The deviations in primary production for MBU were low, even in comparison to the deviations observed in the unit fluids in place values. This trend basically continued for the remainder of the unit history (total production-Table 4-11). The deviations in gas production were higher in primary production and lower in secondary production. The deviations for total oil and gas production from the 12-section area were as expected greater (on a normalized basis) than deviations for equivalent values for the unit.

Conclusions

Variations in original oil and gas in place were greater for the relatively unexplored 12-section area in comparison to the variations of the same parameters in the well defined Monument Butte Unit. The reservoir scale used in representing the MBU did not affect the production response from the unit significantly. The variability in primary and secondary production from MBU for different geostatistical realizations was low. Thus, reservoir heterogeneity at this scale did not affect primary and secondary response from MBU. No adjustable parameters were used in matching reservoir performance. This approach did not yield good history match, particularly because effect of hydraulic fractures was not incorporated in reservoir description.

References

Deo, M. D., Sarkar, A., Nielson, D. L., Lomax, J. D. and Pennington, B. I.: "Monument Butte Unit Case Study: Demonstration of a Successful Water flood in a Fluvial Deltaic Reservoir," paper SPE/DOE 27749, *Proc.,* SPE/DOE Ninth Symposium on Improved Oil Recovery, Tulsa, Oklahoma (1994) 143.

Hand, J. L., Moritz Jr., A. L., Yang, C-T and Chopra, A. K.: "Geostatistical Integration of Geological, Petrophysical, and Outcrop Data for Evaluation of Gravity Drainage Infill Drilling at Prudhoe Bay," paper SPE 28396, *Proc.*, SPE Annual Technical Conference and Exhibition, New Orleans, LA (1994) 347.

Begg, S. H., Kay, A., Gustason, E. R. and Angert, P. F.: "Characterization of a Complex Fluvial-Deltaic Reservoir for Simulation," paper SPE 28398, *Proc.,* SPE Annual Technical, Conference and Exhibition, New Orleans, LA (1994) 375.

Deutsch, C. V. and Journel, A. G.: GSLIB *Geostatistical Software Library and User's Guide*, Oxford University Press, New York City (1992).

U.S. DOE (1994), *Green River Formation Water Flood Demonstration Project*, Yearly Report.

Table 4-1. D1 sands: Different variogram properties

Property	Variogram: Nested Structure 1			
	Model	Range	Sill	Vertical anisotropy
Thickness	Spherical	2000	0.75	1.0
Porosity	Spherical	2000	0.80	0.000956
Saturation	Spherical	1200	0.75	0.00119

Note - The lateral anisotropy is 1.0 for all the properties.

Table 4-2. D1 sands: Additional variogram properties

	Variogram: Nested Structure 2			
Property	Model	Range	Sill	Vertical anisotropy
Thickness	Exponential	4000	0.25	1.0
Porosity	Exponential	4000	0.20	0.000797
Saturation	Spherical	3000	0.25	0.00159

Table 4-3. B2 sands: Different variogram properties

Property	Model	Range	Sill
Thickness	Spherical	1450	1.0
Porosity	Spherical	2400	1.0
Saturation	Spherical	1700	1.0

Table 4-4. B2 sands: Additional variogram properties

Property	Major anisotropy angle	Lateral anisotropy	Vertical anisotropy
Thickness	Omni	1.0	1.0
Porosity	Omni	1.0	0.0003
Saturation	Omni	1.0	0.0018

Table 4-5. Statistical variations of fluids in place for several geostatistical realizations

Statistics	Entire 12-section area		Monument Butte Unit	
	OOIP (Mstb)	OWIP (Mstb)	OOIP (Mstb)	OWIP (Mstb)
Mean	54176	23477	10073	4019
Standard Deviation	8446	4333	653	336
High	70998	33175	10926	4440
Low	40490	17268	8518	3187

Table 4-6. Statistical variations of OOIP (MSTB) for B2 sands

Statistics	12-section area	MBU
Mean	64365	10145
Standard Deviation	11368	1154
High	84159	12307
Low	48502	7768

Table 4-7. Geostatistical property sets used for reservoir simulations

Simulation ID	Thickness	Porosity/permeability	Water saturation
1	Set 1	Set 1	Set 1
2	Set 2	Set 1	Set 1
3	Set 1	Set 2	Set 1
4	Set 1	Set 1	Set 2
5	Set 2	Set 2	Set 1
6	Set 2	Set 1	Set 2
7	Set 1	Set 2	Set 2
8	Set 2	Set 2	Set 2

Table 4-8. Statistical variations of fluids in place for the eight realizations used in reservoir simulations

Statistics	Entire 12-section area		Monument Butte Unit	
	OOIP (Mstb)	OWIP (Mstb)	OOIP (Mstb)	OWIP (Mstb)
Mean	65328	27603	11221	4218
Standard Deviation	5147	2595	755	283
High	72734	31336	12474	4673
Low	57973	23432	10275	3873

Table 4-9. Comparison of the performance of the Monument Butte unit at two different reservoir scales

	Simulation of MBU as an isolated reservoir		Simulation of MBU as a subset of the 12-section area	
	Oil (Mstb)	Gas (MMscf)	Oil (Mstb)	Gas (MMscf)
Primary Production	376	1162	375	1198
Secondary Production	522	2235	519	2253

Table 4-10. Statistical variations in primary productions for eight reservoir simulations using property sets shown in Table 3

Statistics	Entire 12-section area		Monument Butte Unit	
	Oil Produced (Mstb)	Gas Produced (MMscf)	Oil Produced (Mstb)	Gas Produced (MMscf)
Mean	563	1522	385	1212
Standard Deviation	49	207	7	26
High	616	1763	395	1254
Low	500	1295	375	1177

Table 4-11. Statistical variations in total production for eight reservoir simulations using property sets shown in Table 3

Statistics	Entire 12-section area		Monument Butte Unit	
	Oil Produced (Mstb)	Gas Produced (MMscf)	Oil Produced (Mstb)	Gas Produced (MMscf)
Mean	1181	6177	538	2298
Standard Deviation	85	335	14	24
High	1288	6648	565	2338
Low	1076	5717	519	2253

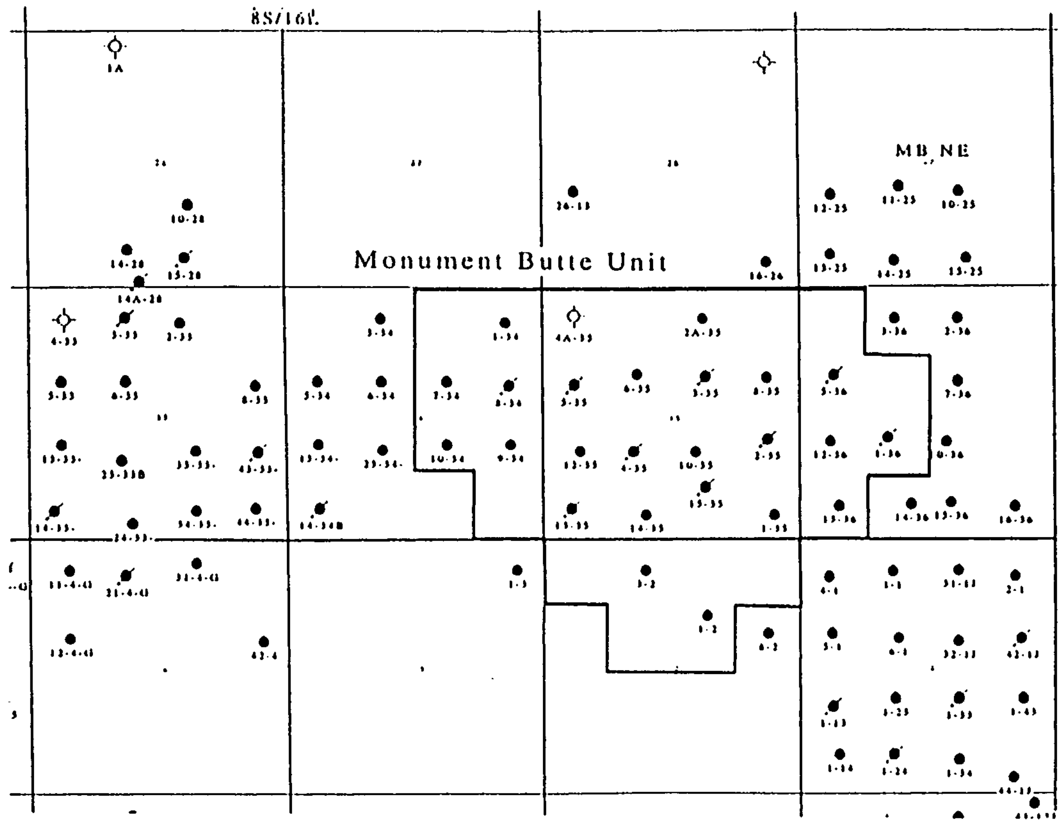


Figure 4-1. The 12-section area around the Monument Butte unit used in reservoir simulations

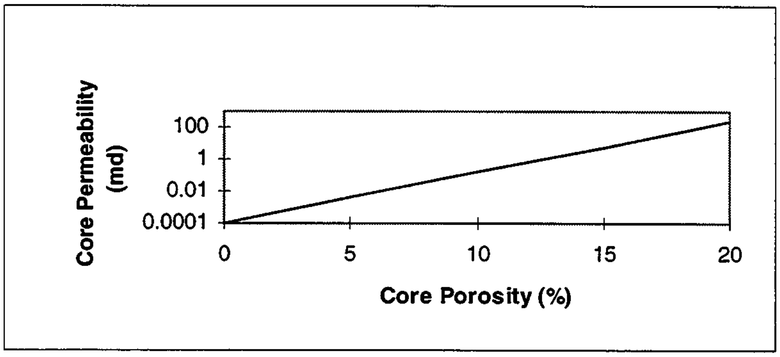


Figure 4-2. Porosity-permeability cross plot

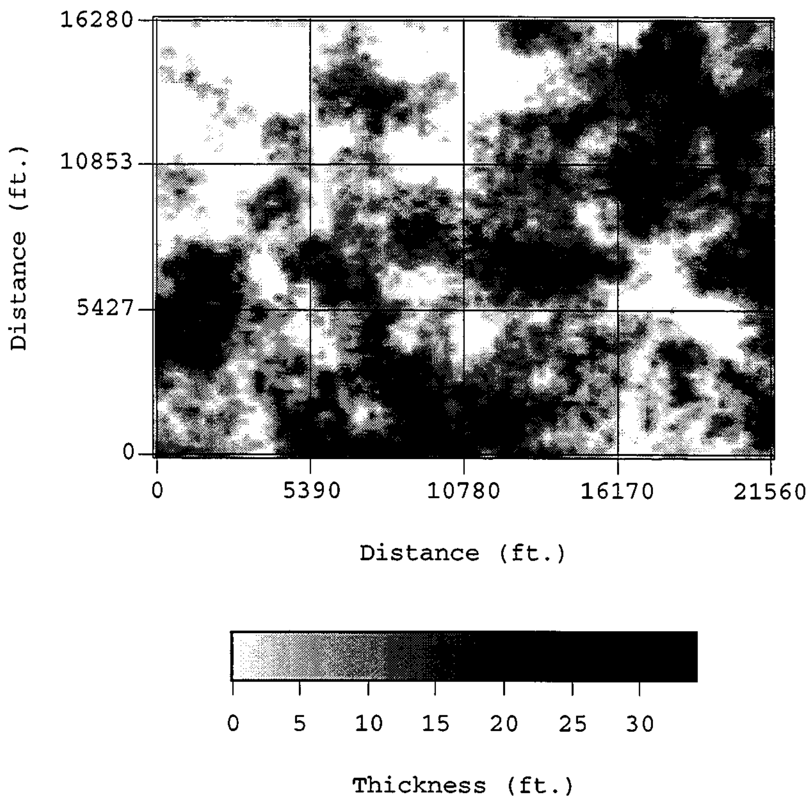


Figure 4-3. Thickness distribution of D1 sands in the 12-section area

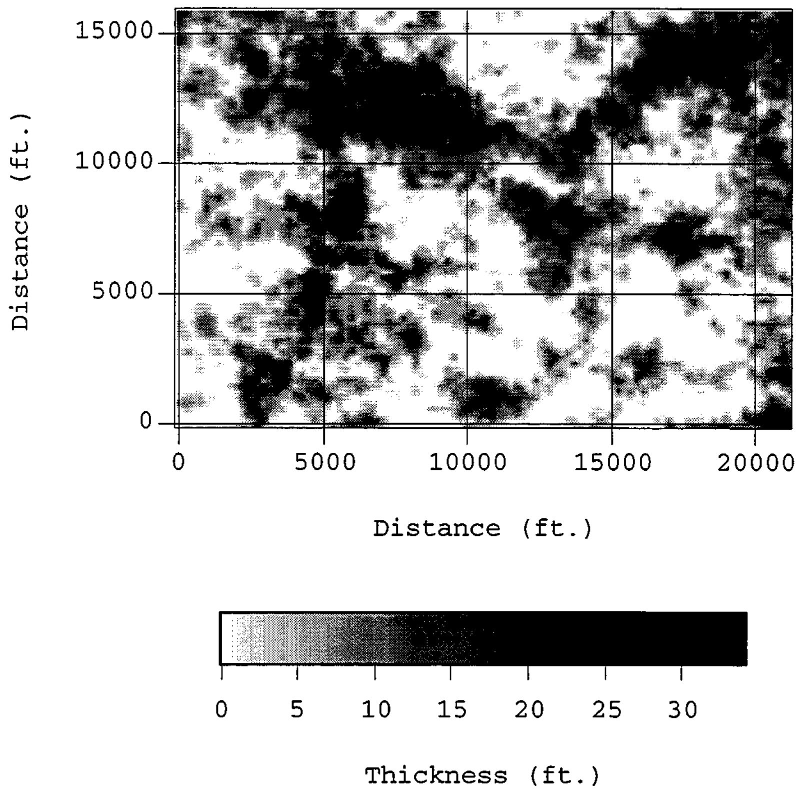


Figure 4-4. Thickness distribution for B2 sands in the 12-section area

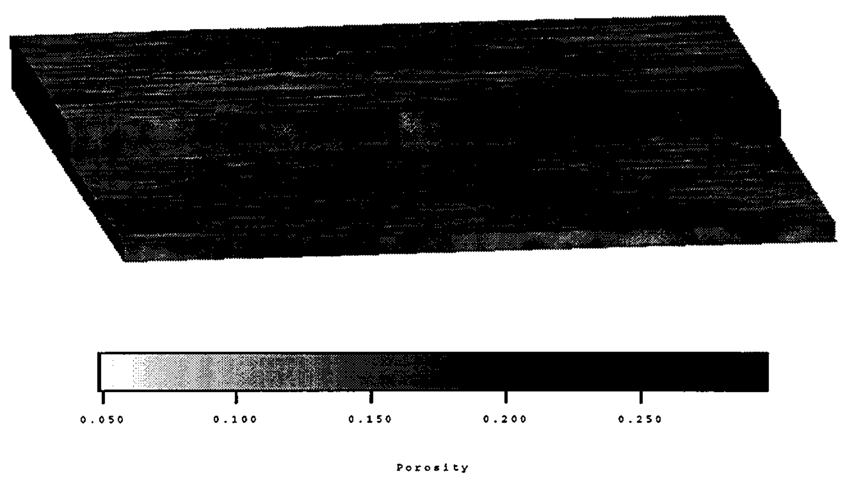


Figure 4-5. Porosity distribution of D1 sands in the 12-section area

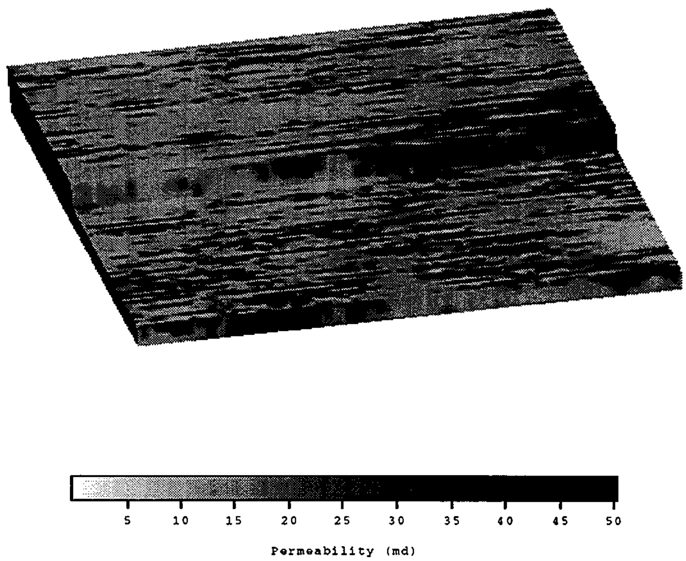


Figure 4-6. Permeability distribution of D1 sands in the 12-section area

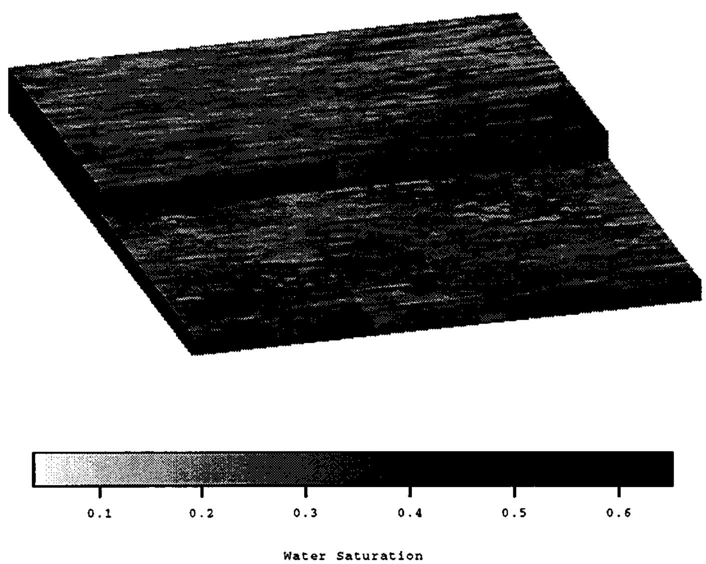


Figure 4-7. Water saturation distribution for D1 sands in the 12-section area

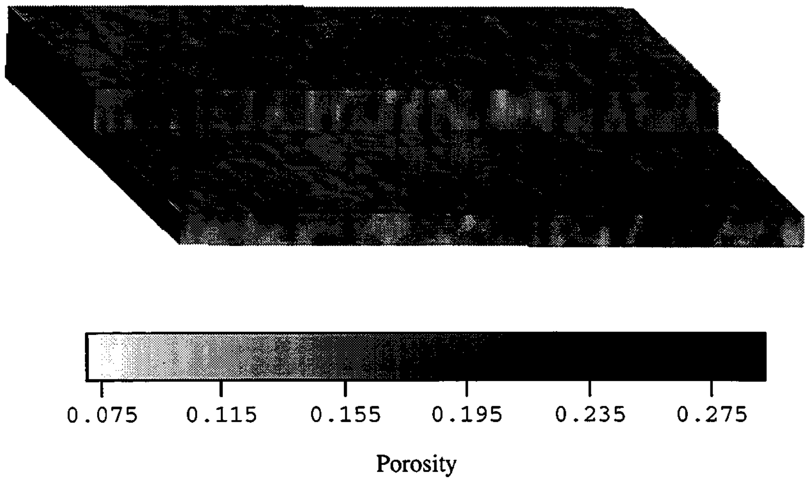


Figure 4-8. Porosity distribution of B2 sands in the 12-section area

Chapter 5. Reserve Considerations and Economics

Reserves

Eighteen wells were drilled and completed in the Monument Butte Unit as of November 1987, and the cumulative production from these wells from September 1981 through November 1987 was 413,830 bbls of oil, 1,646,968 MCF of gas and 11225 bbl of water. The unit reservoir engineering committee in their reserve report estimated remaining primary oil reserves at 27,000 bbls oil using production decline analysis techniques. The field was rapidly becoming uneconomic. Further primary development was not economic, and unless a secondary recovery project could be implemented, the Green River sand play was over.

In November 1987 water injection was commenced on a pilot water flood. At that time the field was producing approximately 40 bbls of oil per day (BOPD), 410 MCF of gas per day, and 2 bbls of water per day. Over the next six months, production continued to decline to about 35 BOPD. At that time, the decline in production rate appeared to cease, and by April, 1989 after an additional 12 months of injection and cumulative injection volume of 355, 927 bbls of water, oil production had increased to 125 BOPD, and the gas-oil ratio had declined from 7750 scf/bbl to 1800 scf/bbl. In August 1991, 46 months after initial injection and with a cumulative injection volume of 1,287,726 bbls of water, production peaked at an average of 360 BOPD. A consulting reservoir engineering firm on January 1, 1992, estimated remaining recoverable reserves to be 1,382,319 bbls of oil, representing ultimate reserves of 2,021,445 bbls (about 20% OOIP). On January 1, 1996 the cumulative oil production was 1,342,146 bbls of oil with remaining oil reserves estimated at 1,001,806 bbls of oil representing an ultimate recovery after water flood of 2,343,952 bbls of oil, versus estimated ultimate recovery under primary of 440,830 bbls of oil. This recovery represents about 21% of the original oil in place in the D and the B sands, the only sands being waterflooded in the Monument Butte unit.

The secondary to primary recovery ratio for the Monument Butte unit (as of April 30, 1996) was about 2.6 and is estimated to be about 5.6 ultimately. The primary recovery was low due to the fact that the initial reservoir pressure was very close to the initial bubble point pressure leading to high gas production and precipitous decline. High paraffin content of the crude also contributed to well bore plugging and production problems, lowering primary recovery. The ultimate recovery of 21% is low compared to other water floods and is due to poor areal sweep.

Normally individual Green River sand fields in this part of the basin will be approximately the same size as the Monument Butte Unit; however, there are other considerations that need to be taken into account prior to forming a unit or commencing a water flood. In most wells there are three to five sands that are potential commercial reservoirs, although usually only one or two will have enough lateral extent for three or more wells to intersect the sand. Therefore, when one or two sections are drilled up on forty acre spacing, there may be two or more water floods active in separate reservoirs. This situation currently exists in the Monument Butte Unit Green River formation D and B sands. The D sand was first water flooded as an individual sand to establish the viability of secondary recovery in this sand. When this was successful, water flooding of B sand began. Production rates, injection rates, and pressures were monitored, and the results indicated that the additional water flood was also successful. This is an important concept because, unlike many reservoirs that cover large areas, in this area there is considerable oil in place but the reservoirs are relatively small in areal extent, although they stack up and overlap so that more than one sand can be water flooded simultaneously. Being able to combine water floods enhances the economics through increased reserves and increased production rates.

Detailed geological mapping with extensive cross section evaluation, will define the reservoirs that need to have extensive reservoir evaluation. In some cases, rotary sidewall cores, and or one or more of the sophisticated logging programs will be needed to aid the reservoir evaluation. The FMI log is most helpful for evaluating fracturing, thin bed stratigraphy, and picking appropriate core points. The MIRL log is valuable for determining effective permeability, fluid content of the reservoir along with the relative mobility of the oil and water. Good reservoir characterization and definition will determine the potential for development of a commercial water flood. Even though the FMI and the MRIL logs provide useful reservoir data, it is not practical (in an economic sense) to use these tools on every well that is drilled. These logs should be used to calibrate the reservoir information from other suite of logs. It is difficult to generalize the frequency with which these logs ought to be employed. From a reservoir characterization viewpoint, it is advisable to use the FMI at least once in a one to two square mile area while MRIL could be used once in a two to three square mile area. Once again, these guidelines are valid only in the immediate vicinity of the field and are likely to change depending on the complexity of the geologic environment and the economics of the entire project.

Success of the Monument Butte Unit, and the indication of response in the Jonah Unit, Gilsonite Unit, and Wells Draw Unit, all of which have had indications of response to injection, supports the theory of the floodability of the Green River sands. These last three units are not part of the DOE Study, although, they were all started as a result of the Monument Butte success. The water flood in the Travis unit was put on hold due to water channeling problems. This is believed to be due to the lithologic complexity of the Lower Douglas Creek reservoir (please see the discussions in Chapter 3) and due to the 20-acre spacing and hydraulic fracturing practices. At the present time, the unit is being reevaluated. The Boundary Unit had not started water injection as of January 1996. The Boundary unit has eight to ten possible water flood targets, some of which have oil-water contacts. This makes designing and operating the water flood more complicated. As of April 1996, in the study area, there are eight active water flood units, with two more being formed. In the immediate area of the trend play there are six more active water flood units, all of which have been started after Monument Butte Unit became successful. With fourteen active units, and others being formed, the magnitude of this play begins to take on significant proportions. It is projected that with the water floods now active the potential recoverable reserves will exceed more than thirty million barrels of oil, and when the trend is fully developed the potential reserves will exceed one hundred million barrels of oil.

Economics

As water flood operations continue throughout the Monument Butte area of the Uinta Basin, operators continue to evaluate their investment decisions in order to obtain the best possible internal rate-of-return. Considerations such as taxes, drilling and completion cost, cost of capital and oil prices become increasingly important as additional water flood projects are implemented. Oil and gas companies typically value reserves on a *time value of money* basis commonly referred to as the Net Present Value (NPV). Each Net Present Value calculation must be discounted for the imputed cost of capital. The assumed cost of capital for this analysis is 10% (NPV-10).

Economics of the Monument Butte Unit

As of September 1987 primary production had been 405,000 barrels of oil. Reservoir engineers estimated approximately 27,000 barrels remaining reserves and the field was producing 40 barrels of oil per day. At this time the field was $1,635,000 from payout and with the remaining reserves it would never payout. Water injection began in October, 1987 and by September, 1993 the field had a positive net revenue of $1,733,000 for this period (October 1987 - September 1993). From September, 1993 to August, 1996 the Unit had an additional positive net revenue of about $751,624, for a total net revenue of about $2,484,624. In addition, the discounted value (NPV-10) of the remaining reserves within the Monument Butte Unit, as of July 1, 1996 was $11,851,260.

Future Development Model

Due to the success of the Monument Butte water flood project, and the successful transfer of technology, development drilling within the area is being pursued by Inland Resources as well as other operators. As development drilling advances, new economic scenarios evolve as oil production rates verses time change from those observed at the Monument Butte Unit. At the Monument Butte Unit, primary depletion of the reservoir was allowed to persist for the first 5-6 years of production before the first water was injected into the reservoir. In most cases, revenue from oil production was not adequate to provide a return in excess of the initial capital required to drill and complete the wells. This situation allowed a large portion of time to elapse during which net revenue from oil production was providing only a marginal, if any, rate-of return on the initial capital investment. In order to maximize the rate-of-return, current development drilling programs allow for the conversion of producers to injectors within the first 6-8 months of the initial production of the well. This practice has allowed the reservoir pressure to be maintained, as opposed to allowing the well to cycle through a full depletion history and subsequent repressurization, as experienced at the Monument Butte Unit.

Investment Units

Economic modeling of the development program has been broken down into basic building blocks called "Investment Units". An Investment Unit considers the cost of drilling and completion operations for two wells versus the revenue generated by oil production over time. The economics of an investment unit assumes that both well are drilled and completed as producers with one well being converted to an injector 6 months after the production is established. Each well is drilled on a 40 acre tract, thus each investment unit consists of 80 acres (2 wells x 40 acres). Investment units are intended to be drilled in groups with a minimum of 8 investment units drilled contiguously. Multiple investment units must be drilled in order to achieve full five-spot injection pattern. Without full five-spot injection patterns, an investment unit may not perform to its full potential. (See Figure 5-1).

Type Decline Curve

Production histories from wells within the Monument Butte area (Figure 5-2) were analyzed in order to develop a most likely case scenario for production rates versus time. Since both wells within the investment unit are initially produced, the historical decline curve is multiplied by a factor of 2. Average historical initial production (I.P.) rates were observed to be approximately 125 BOPD. During the first 6 months of production both wells are produced. During this period, production declines at approximate 85% exponential decline,typical of wells with no pressure support. After 6 months of production from both wells, one of the wells is converted to an injection well for the purpose of providing pressure support for the offset well. At this point, the production from the investment unit is reduced by ½, in order to reflect the dedication of one well to a water injection well. Over the next six months, production continues to decline from the one remaining producer until the effects of injection have been realized. At this time, production begins to gradually rise as reservoir pressure builds. The single producing well eventually peaks at a stabilized production rate of approximately 65 BOPD. This rate declines slightly at 8% per year over the next 4 years until water breakthrough occurs. At water breakthrough, the decline accelerates to a 25% exponential decline until the investment unit reaches its economic limit of approximately 7 BOPD (Figure 5-3). At the economic limit, the cost to operate both the injection well and the producing well are in excess of the revenue from the producer.

Conclusions

The model requires assumptions to be made regarding the cost of drilling and completion, taxes, royalties, operating cost and oil price. The following model assumptions have been made based on historical data:

Assumptions:

DRILLING AND COMPLETION COST (2 WELLS)	$700,000.00
WORKING INTEREST	100.0%
NET REVENUE INTEREST (Working Interest minus royalty)	85.0%
OIL PRICE	$17.75
TAXES	4.5%
LEASE OPERATING EXPENSE	$1400.00/MO

Conclusions:

NET PRESENT VALUE @ 10%	$865,857.00
LIFE OF PROJECT IN YEARS	16.0 YEARS
RATE-OF-RETURN	48.8%
PAYOUT	3.12 YEARS

Based on the assumptions above, the economic model was run in order to value a typical investment unit. The main purpose of the economic model is to calculate the value of the investment unit at the time the initial investment is made. The Net Present Value calculation is used to discount the value of the investment based on the time require to recover the cost of the initial capital requirements and realize a return on the investment. The profit of the investment unit is $865,857.00. It is important to note that the profit of the investment unit is net of the $700,000.00 initial investment cost, i.e. the discounted revenue pays back the capital investment in 3.12 years and has a cumulative discounted cash flow of an additional $865,857.00. In addition, payout, rate-of return, and project life were evaluated by evaluating cash flows on a monthly basis and are summarized below. The economic results of the Development Drilling Type Decline curve are superior in all categories to the actual Monument Butte Decline. The difference is attributable to the commencement of injection at a much earlier time. Early injection allows higher volumes of oil to be recovered within a shorter period of time and thus provides a higher rate-of-return.

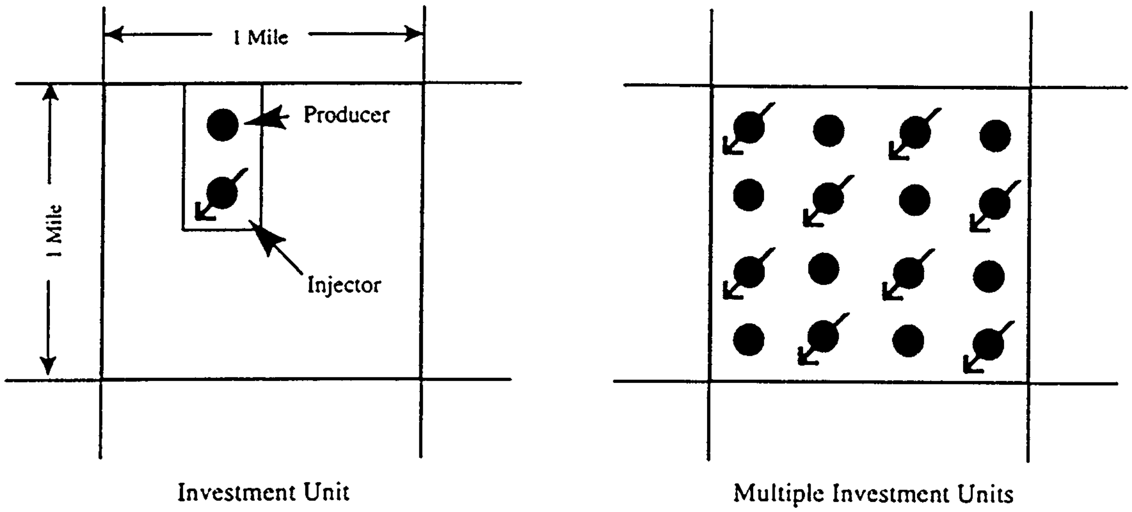


Figure 5-1. Investment unit in a five-spot water flood development

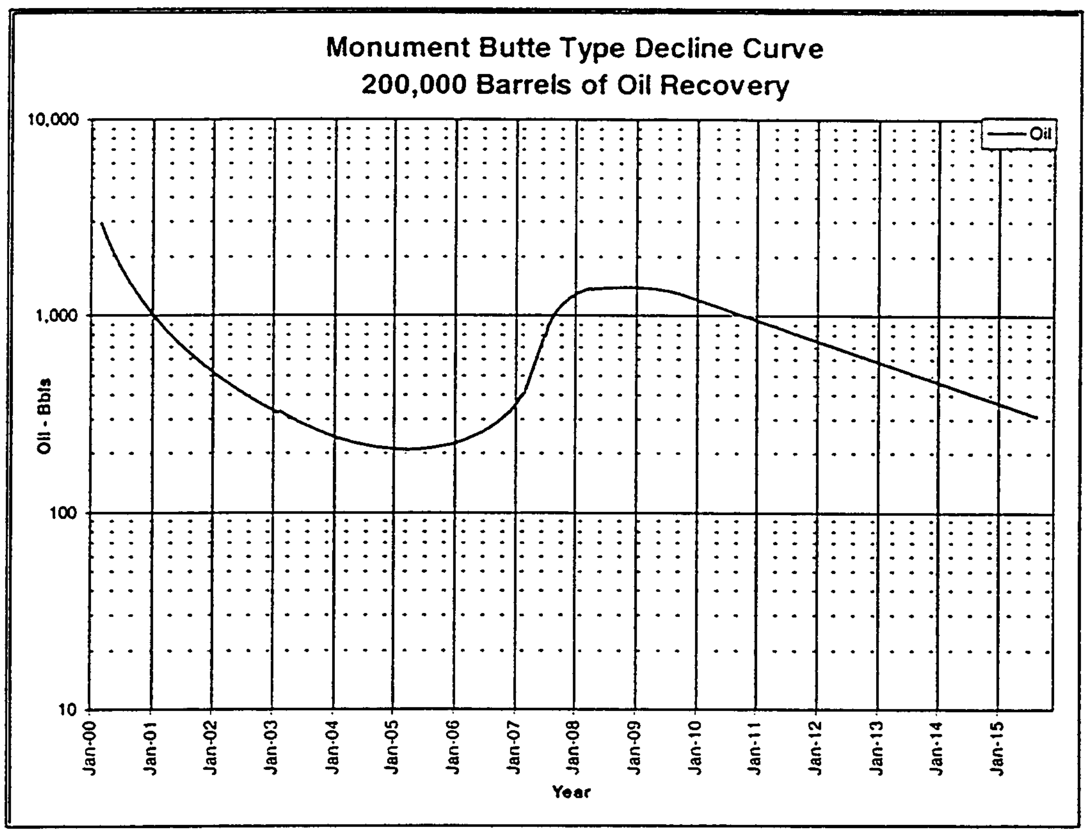


Figure 5-2. Historical (average) Monument Butte decline curve

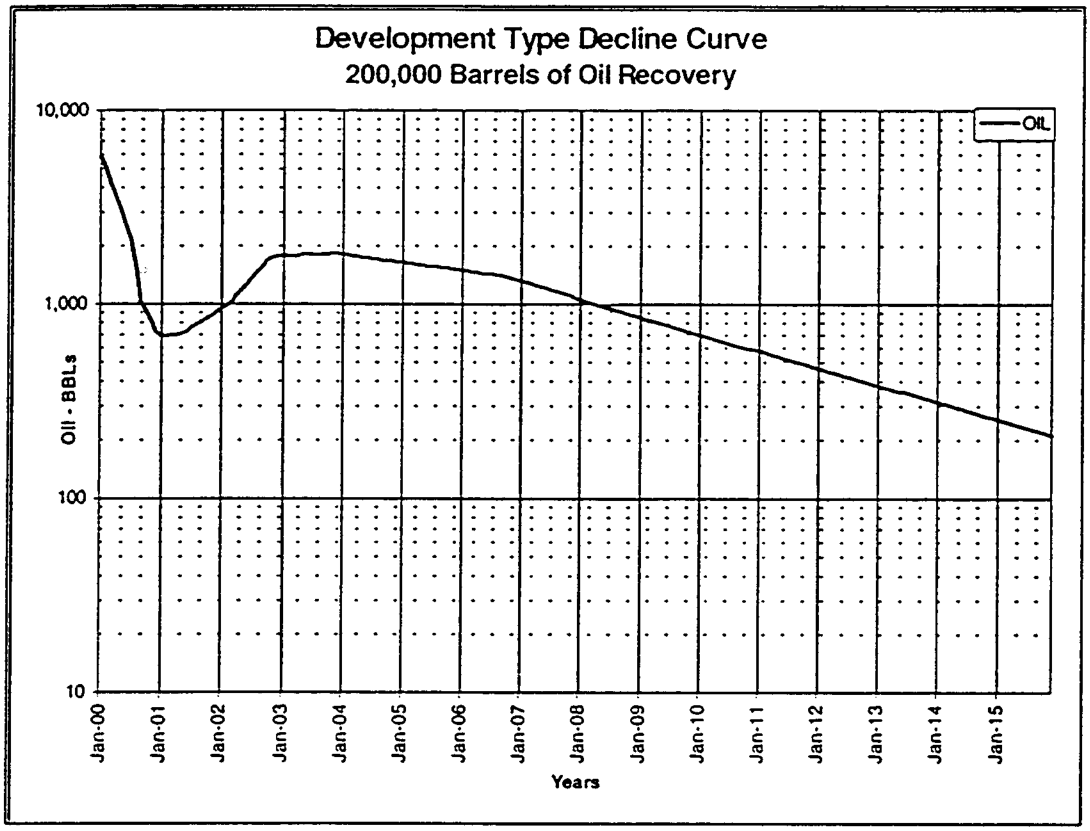


Figure 5-3. The decline curve used for the economic analysis

Chapter 6. Technology Transfer

As part of the Monument Butte expansion, more than 30 wells have already been drilled. Primary production from each of these expansion units has been better than the original Monument Butte unit at around the same stage in the life of the reservoir. Water floods have been started in the expansion units recently and production wells have not yet responded. The water floods in the Jonah and the Wellsdraw units were begun as a direct consequence of the success of the Monument Butte water flood. These floods have had good success. The oil production rate in the Jonah unit has approximately tripled while that in the Wellsdraw unit has nearly doubled since the inception of their respective water floods.

The following is a list of papers and other publications that resulted due to this project.

List of Papers and Publications

1. Water Flood Project in the Monument Butte Field, Uinta Basin, presented by John D. Lomax, Annual meeting of the Interstate Oil and Gas Compact Commission, December 6-8, 1992, Salt Lake City, Utah.
2. Water Flood Project in the Uinta Basin, presented by Milind D. Deo, Monthly meeting of the Salt Lake section of the Society of Petroleum Engineers, February 16, 1993, Salt Lake City, Utah.
3. Potential of Water Flooding in the Uinta Basin, presented by Milind D. Deo, Monthly meeting of the Uinta Basin section of the Society of Petroleum Engineers, March 25, 1993, Vernal, Utah.

4. Green River Formation Water Flood Demonstration Project Showing the Development of New Reserves in the Uinta Basin, presented by John D. Lomax, meeting of the Workshop for Independent Oil & Gas Producers in the Appalachian & Illinois Basins, June 4, 1993, Lexington, Kentucky.
5. Green River Formation Water Flood Demonstration Project Showing the Development of New Reserves in the Uinta Basin, presented by John D. Lomax, meeting of the Subcommittee on Renewable Energy, Energy Efficiency and Competitiveness of the U.S. Senate
6. Committee on Energy and Natural Resources held on November 30, 1993, Roswell, New Mexico.
7. Monument Butte Case Study, Demonstration of a Successful Waterflood in a Fluvial Deltaic Reservoir, Deo, M. D., Sarkar, A., Nielson, D.L. and Lomax, J.D. and Pennington, B.I.,
8. SPE 27749, Paper presented at the Improved Oil Recovery Symposium of the SPE and the U.S. DOE in Tulsa, Oklahoma, April 17-20, 1994.
9. Green River Formation Water Flood Demonstration Project, Yearly Report published by the U.S. DOE, 1994, 89pp.
10. Description and Performance of a Lacustrine Fractured Reservoir, Deo, M. D., Neer L. A., Whitney, E. M., Nielson, D. L., Lomax, J. D. and Pennington B. I., SPE 28938, Paper to be presented in the Poster Session of the Annual Fall Meeting of the Society of Petroleum Engineers.
11. Solids Precipitation in Reservoirs Due to Nonisothermal Injections, Deo, M. D., SPE 28967, Paper presented at the SPE International Symposium on Oil Field Chemistry, San Antonio, Texas, February, 1995.

12. Green River Formation Water Flood Demonstration Project, Yearly Report published by the U.S. DOE, 1995, 60pp.

13. Effect of Reservoir Connectivity on Primary and Secondary Recovery, Pawar, R. J., Deo, M. D. and Dyer, J., SPE 35414, Paper to be presented at the SPE/DOE Improved Oil Recovery Symposium in Tulsa, Oklahoma, April, 1996.

Chapter 7. Summary and Conclusions

The primary objective of the project to understand the Monument Butte water flood and to encourage the implementation of secondary recovery processes in similar units was successful. Continued application of water flood in the unit increased production more than twice the total primary production. The total reserves estimated after primary production increased more than five times once results from the flood were considered. Water flood was applied in the nearby Jonah and Wellsdraw units with significant success.

Water flood in Monument Butte was successful because it targeted sands that were laterally continuous and lithologically homogeneous. The performance of the reservoir was similar to that of a typical undersaturated reservoir whose initial reservoir pressure was close to the initial bubble point pressure. The repressurization of the reservoir in secondary recovery was accelerated by converting some of the best producers to injectors. Fresh water was injected to maintain compatibility with the reservoir fluids.

Lower Douglas Creek unit, a lensy, isolated, lithologically heterogeneous reservoir was the target of the water flood in the Travis unit. Over the duration of the project, the Travis water flood was unsuccessful. A list of reasons for the failure of the water flood in Travis is given below. The failure may have resulted due to any one or any combination of these reasons.

- Geologic complexity, lithologic heterogeneity.
- A hydraulic fracture in well 15-28 (the primary injector in Travis) that channeled water to units other than the target.

- Opening of and short circuiting through natural fractures due to the high injection rate in well 15-28.

The FMI log in well 14a-28 did help identify the D1 producing horizon in Travis, which was later opened in a few other wells. This proved to be a decent primary production target. However, water flood in D1 also resulted in premature water breakthrough without significant additional oil production. The interconnecting hydraulic fractures between the injector and the producer may have contributed to this. This established that caution should be exercised when creating hydraulic fractures particularly at 20-acre spacing.

The planning and implementation of a water flood in the Boundary unit highlighted the difficulty in the application of this technology in these reservoirs. There were about eight target zones and the lateral continuity of several of these zones was questionable. There were only six control points (wells). Water-oil contact was observed in one well in the D1 horizon. Of the possible targets, the C sandstone unit appeared most promising and water flood was begun in early 1996. At the current time (April 1996), all indications are that this water flood will be successful.

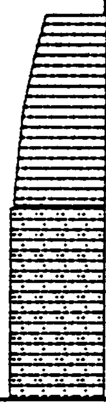
The reservoir characterization activities undertaken in this project such as advanced well logs (Formation Micro Imaging and Magnetic Resonance Imaging), full-diameter and side-wall cores, etc. provided better understanding of reservoirs involved. In some cases, these methods led to the discovery of commercially producible zones. PVT properties, permeabilities, relative permeabilities, etc. were measured, primarily since they were required as input for reservoir simulation. Reservoir simulation was performed at different resolutions and scales. History of all of the three units was matched reasonably well. In addition, geostatistical reservoir images were generated of large areas in the Greater Monument Butte region. Thermodynamics of wax precipitation in these waxy-oil reservoirs was modeled along with an analysis of reduction in recovery that might result due to wax precipitation in injection operations. A modest microbial treatment program undertaken in Monument Butte to address the wax problem in production wells was reasonably successful, reducing hot-oil treatments required.

Technology transfer was the most successful component of the project. The project resulted in four (4) SPE papers, two(2) AAPG papers and presentations in several national and international meetings. This project revived the oil-drilling activity in Utah's Uinta basin. This is evidenced by the fact that the drilling planned for 1996 (112 wells) exceeds the wells drilled in the region in 1993 fourfold. Wells in the Gilsonite unit are showing a good response while the oil production rate in Balcron's Jonah unit has increased about three times the pre-water flood production. Production rate in the Wellsdraw unit has also almost doubled.

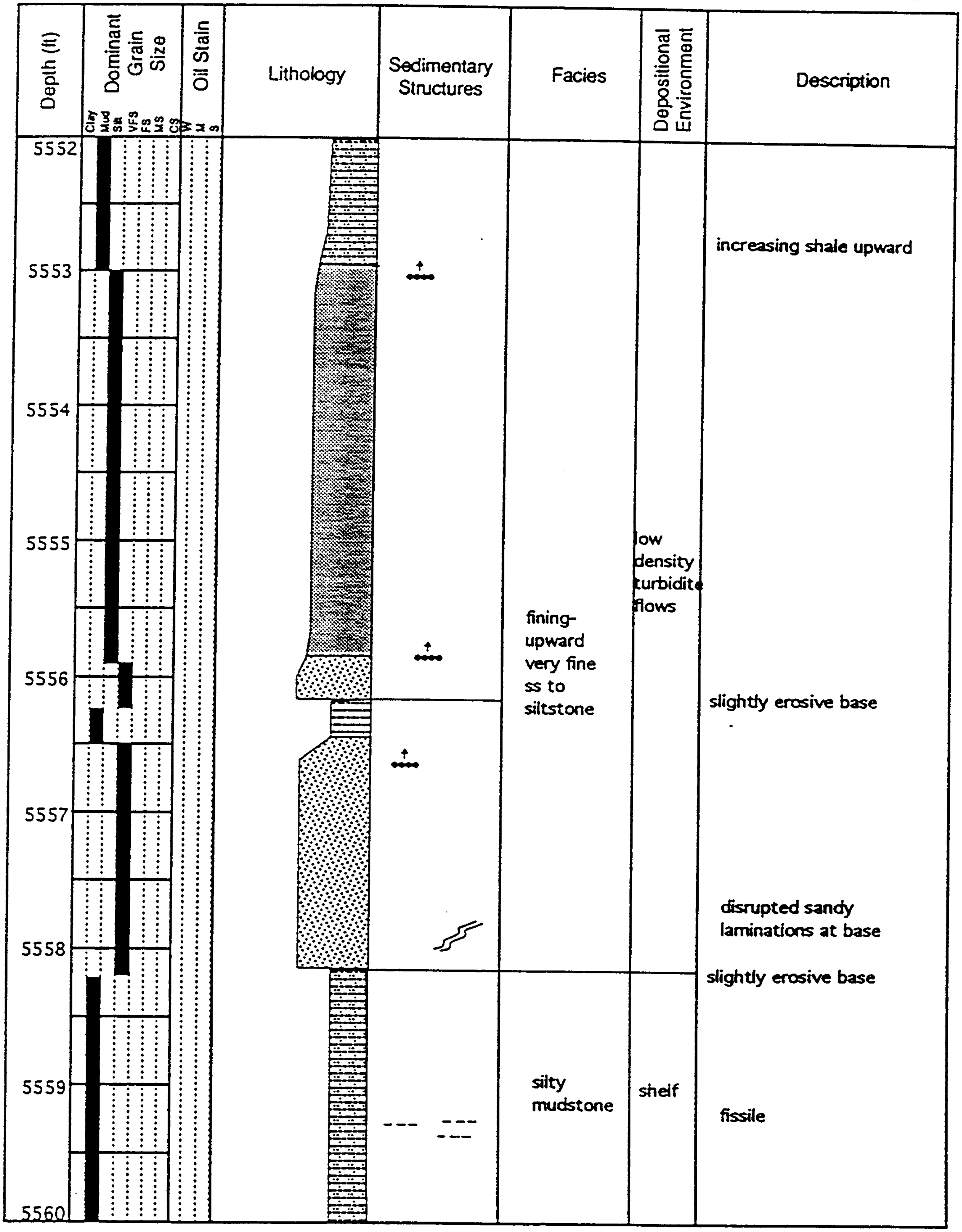
There is no reason why the successful Monument Butte flood technology can not be applied to about 300 square miles in the Greater Monument Butte region. The targets must be chosen carefully, and the hydraulic fractures must be carefully designed.

APPENDIX A - Detailed lithologic log of core and X-ray diffraction analyses from Travis Federal #14A-28.

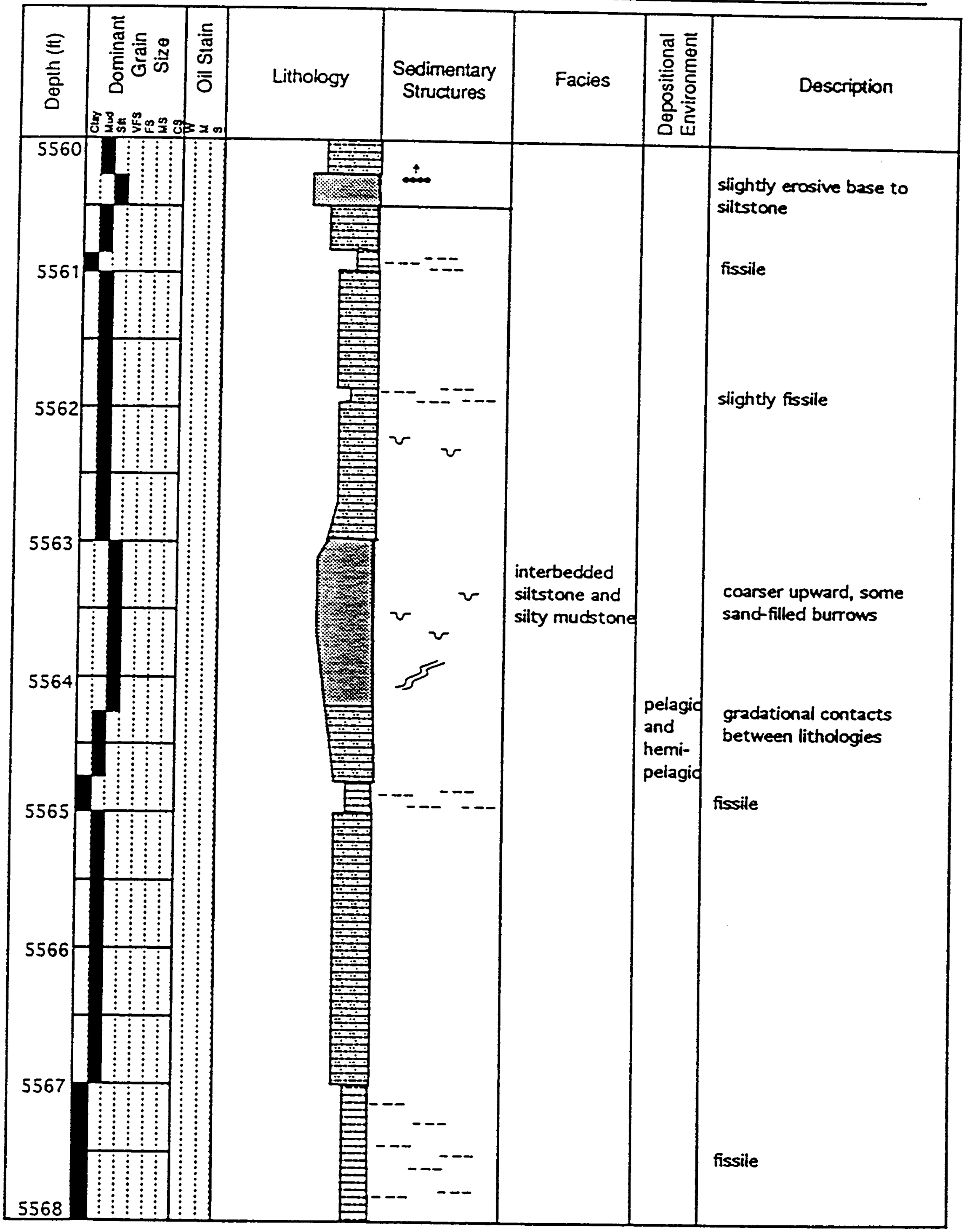
Well: #14A-28 Monument Butte Interval: Top 5550 - 5552

Depth (ft)	Dominant Grain Size (Clay, Mud, Slt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
			TOP OF CORE				
5550							
5551					Shale	off shore	increasing shale and fissility upwards
5552							

Well: #14A-28 Monument Butte Interval: 5552 - 5560



Well: #14A-28 Monument Butte Interval: 5560-5568



Well: #14A-28 Monument Butte Interval: 5568-5576

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5568–5570					silty mudstone	hemi pelagic	medium gray mudstone, breaks conchoidally, abundant very fine organic material
5570–5572			FX	?	planar laminated very fine gr calcareous ss	shelf bar	light gray very fine grained sandstone, carbonate cement, sharp basal contact and gradational upper contact
5572–5573					bioturbated shaly siltstone	hemi pelagic	fining-upward to mudstone, slightly smeared _Chondrites_ burrows at base
5573–5574					disrupted laminated ss	slump	disrupted and inclined laminations in a semicoherent block of sediment, sharp upper and lower contacts
5575–5576					slightly disrupted siltstone	shelf	light gray siltstone, one sandy lamination is offset by a synsedimentary fault

Well: #14A-28 Monument Butte Interval: 5576-5584

Depth (ft)	Dominant Grain Size (Clay, Mud, Slt, VFS, FS, MS, CS)	Oil Stain (W, M, S)		Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5576						siltstone	shelf	light gray siltstone, subhorizontally laminated with some sandier laminations
5577						planar laminated very fine ss	shelf bar	not oil-stained, wave-reworked top of turbidite channel ?
5578 5579 5580						mostly rippled ss	turbidite channel	abruptly oil-stained below: two 2 cm-thick coarse ss laminations; rippled top to dewatered flame structures to planar laminated base
						slumped calcareous ss	channel base?	speckled with white carbonate cement, shale stringers
5581 5582			FX			convoluted to disrupted laminated ss	slump	inclined, disrupted lams; calcareous ss laminations cut by small synsedimentary faults; medium gray (weakly oil-stained)
5583 5584						slightly disrupted siltstone	shelf	homogeneous light gray siltstone, some disrupted sandy lens

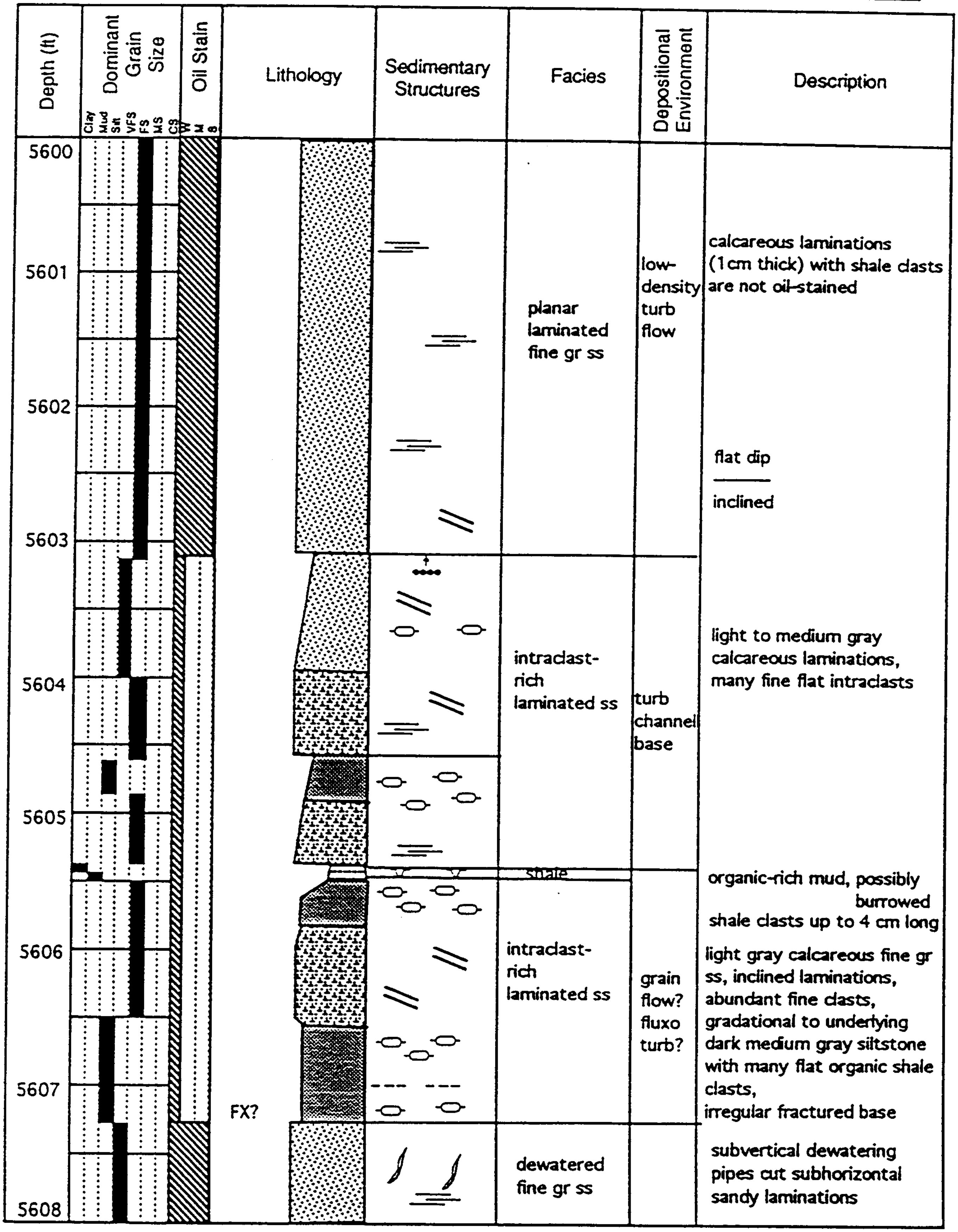
Well: #14A-28 Monument Butte Interval: 5584-5592

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5584–5588 (5584, 5585, 5586, 5587)				Py Py	slightly disrupted siltstone	shelf	faint subhorizontal sandstone mottles homogeneous light gray siltstone, abundant fine organic debris, small pyrite nodules, core breaks conchoidally at base
5588–5590 (5588, 5589)			FX		planar laminated very fine gr ss	shelf bar	wave-reworked top of turbidite channel? sharp color change with oil-staining (to med gray) some disrupted sandy laminations FX: oil in fx, 2 cm offset along planar subvert fx
5590–5592 (5590, 5591, 5592)					planar laminated fine gr ss	low-density turb flow	dark brown-gray(oil-stain): rippled top of strongly oil-stained sandstone unit, base at 5603' slightly less oil-stained than below

Well: #14A-28 Monument Butte Interval: 5592-5600

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5592–5597			FX		planar laminated fine gr ss	low-density turb flow	fine organic debris along horizontal laminations 45° closed fracture, fault cuts laminations, offset could be 4-5 cm or more
5597–5598.6							SCAL sample
5598.6–5599					planar lam ss		as above
5599–5600							SCAL sample
5600							as above

Well: #14A-28 Monument Butte Interval: 5600-5608



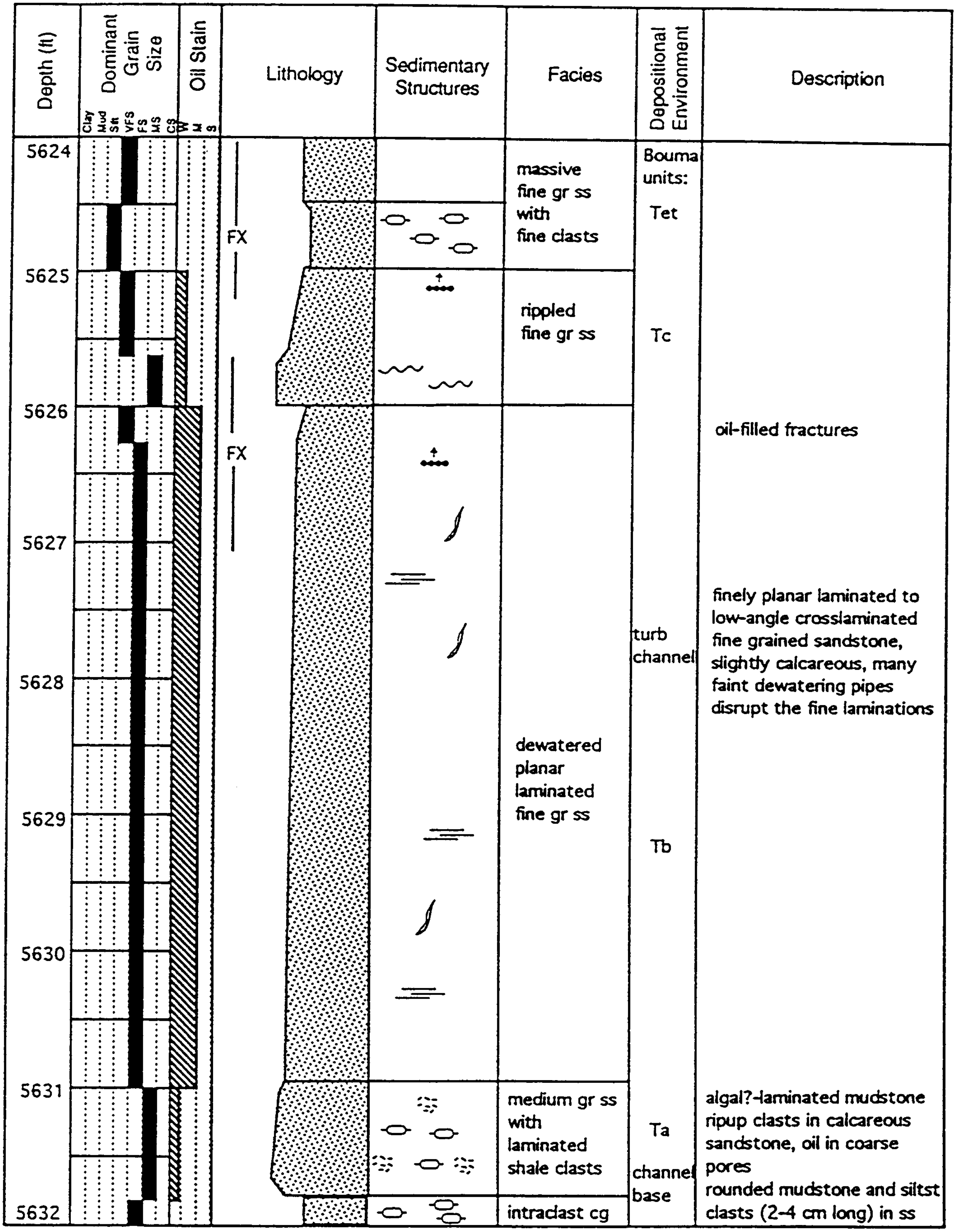
Well: #14A-28 Monument Butte Interval: 5608-5616

Depth (ft)	Lithology	Facies	Depositional Environment	Description
5608	FX	dewatered laminated fine gr ss		5607.3-5609.3: brown (oil-stained) 45° dip on open fx
5609	FX			graded (turbiditic) laminations cut by dewatering pipes, fractures follow pipes???
		disrupted laminated fine gr ss	fluxo turb?	en-echelon microfaults offset slightly calcareous laminations.
5610	FX			planar laminated with synsed faults at top to disrupted laminations to rippled at base
5611				one organic-rich shale clast 4 cm long
		dewatered fine gr ss	slump	light gray calcareous siltst steep dips
5612		rippled very fine gr ss		flat dips ripples-waning energy?
5613		disrupted laminated fine gr ss	slump	calcareous laminations crinkle downward into a founder ball, upper and lower contacts not sharp
5614	FX			
5615		mottled very fine gr ss	grain flow?	medium gray very fine gr ss with lighter (more calcareous) fine gr ss mottles, the mottles are subhorizontal to slightly inclined abundant scattered flat shale intraclasts, inclined hard (silicified?) intraclast at base
5616				

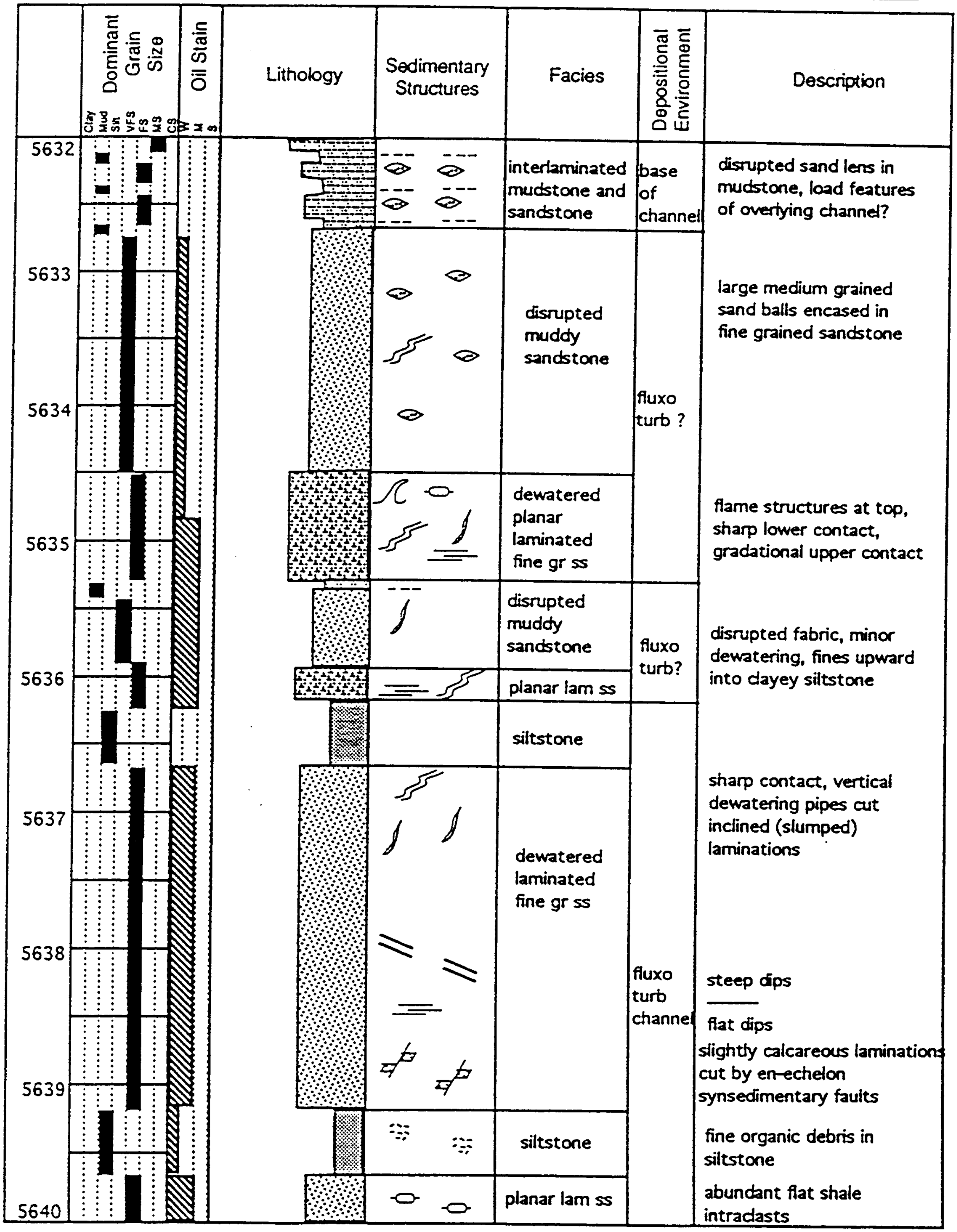
Well: #14A-28 Monument Butte Interval: 5616-5624

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5616					calc siltst		light gray calcareous, subhorizontally laminated, fine debris, gradational lower contact
5617				?	massive very fine ss with clasts	grain flow	very fine grained ss to siltstone with fine shale clasts in middle of bed
5618					disrupted fine gr ss	debris flow	one 3 cm long shale clast at top
5619					siltstone w/ clasts		very fine grained ss to silt stone, many fine (.1 cm) shale clasts, one long laminated shale clast at base (core diameter)
5620					planar laminated fine gr ss	debris flow	
					disrupted ss with clasts		4 cm rounded clast in disrupted gray-brown fine grained ss
5621							SCAL sample
5622–5623					dewatered very fine gr ss	fluidized flow	light to dark gray flame structures and subvertical fluid escape pipes in fine to very fine gr ss, crossbedded base with load structure
							light gray, calcareous siltst with many fine (1 cm long) laminated shale clasts
5624					calc siltstone		

Well: #14A-28 Monument Butte Interval: 5624-5632



Well: #14A-28 Monument Butte Interval: 5632-5640



Well: #14A-28 Monument Butte Interval: 5640-5646 Btm

Depth (ft)	Dominant Grain Size (Clay, Mud, Slt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5640					planar lam ss	channel base	upper fine to medium grained ss with disrupted planar laminations
5641			FX				
5642				poor recovery	massive very fine ss to siltstone with clasts	grain flow	homogeneous gray siltstone, coarsens upward to fine grained sandstone, abundant fine shale clasts, no bedding breaks
5643							
5644							
5645							
5646			BTM OF CORE				

Lomax Exploration Co.

Fed #14A-28

Mineralogy, Approx. Wt.% [X] (or) Relative Abundance [ ]

Sample No.	Quartz	Plagioclase	K- Feldspar	Siderite	Calcite	Dolomite	Pyrite	Chlorite	Illite+ Mica	Mixed-layer Illite-smectite	Amorphous/ Below Detect.	% smectite in illite-smectite	
5595.0-96.0 Bulk	49	32	7		3	4		2	3		-		
Clay								26	74				
5598.0-99.0 Bulk	48	32	6	1?	3	5	Tr	3	2		-		
Clay								25	75				
5615.0-16.0 Bulk	46	26	6	Tr?	5	6	1	4	2	4	-		
Clay								27	28	45		10	illite-rich illite-smectite
5638.0-39.0 Bulk	51	21	6	Tr	14	4	Tr	2	2		-		
Clay								25	75				
5639.0-40.0 Bulk	43	21	5		3	10	3	3	4	8	-		
Clay								9	35	56		10	

MM = Predominant M = Major m = Minor Tr = Trace ? = Tentative Identification

Figure 2. **SUMMARY OF X-RAY DIFFRACTION ANALYSIS**

UNIVERSITY OF UTAH RESEARCH INSTITUTE, EARTH SCIENCE LABORATORY

APPENDIX B - Detailed lithologic log of core and X-ray diffraction analyses from Travis Federal #2-33.

Well: #2-33 Monument Butte Interval: Top 5647- 5654

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5647			TOP OF CORE				
5647–5649					disrupted sandstone laminations in shale	slump	light gray, calcareous ss laminations steeply inclined to vertical XRD gradational contact to underlying grain flow dark gray mudstone with abundant fine organic debris
5649–5650					muddy sandstone with clasts	grain flow to debris flow	sharp contact med gray fine gr ss with abundant fine organic debris and mica, some shale clasts
5650–5652			plug plug plug		disrupted sandstone	slumped turb ss	XRD light gray, calcareous-cemented sandstone with disrupted (slumped) laminations irregular, loaded base
5652–5654			plug FX		slightly disrupted sandy mudstone	shelf	dark gray, fine gr, clayey sandstone with subhorizontal mottles and fine organic debris

Well: #2-33 Monument Butte Interval: 5654-5662

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5654			FX				dark, clayey sandstone
							chaotic top with dewatering pipes and slight oil stain on fractures
5655			plug		massive to dewatered medium gr sandstone		light gray, micaceous, calcareous, low medium grained sandstone with a few scattered shale clasts XRD
5656			plug			fluxo turbidite	thin, vertical dewatering pipes, some synsedimentary microfaults
5657			plug		dewatered fine gr sandstone		coarsens-upward
							inclined laminations in non-clayey sandstone, steeply dipping ~70°, less clasts than below
5658			plug			slumped base	
							above clean fine-med, laminated ss
5659					muddy sandstone with clasts		below XRD muddy fine ss (debris flow)
5660			plug				
5661					shale	slumped debris flow	gradational contacts with overlying and underlying debris flow units, in slump package with debris flows?
5662					muddy ss with clasts		

Well: #2-33 Interval: 5662-5670

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5662 – 5664					muddy sandstone with clasts	slumped debris flow	thick debris flow unit- no shale breaks from 5661.5 to 5664.7', large (10 cm) shale clasts, abundant organic clasts, some deformed laminations
5665					silty shale		gradational contacts, slumped with debris flows?
5665 – 5667					muddy sandstone with clasts	fluidized debris flow	clasts more randomly oriented than below, fine grained sandstone is slightly calcareous (light medium gray color) XRD
5667 – 5668					disturbed shale	slump	steeply dipping disturbed silty laminations in shale XRD
5668 – 5669					muddy sandstone with clasts	slumped debris flow	light to medium gray (calcareous) fine ss, slightly inclined fine flat organic clasts and a few large shale clasts (orange-colored)
5670					disturbed shale	slump	medium gray shale

Well: #2-33 Interval: 5670-5676 Btm

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5670				Py Py	shale	slump?	sharp base on ss, dips 45° fracture or glide plane??
5671			FX?		muddy sandstone with clasts	debris flow	light to med gray sandstone with 12 cm long shale clasts (orange color), abundant fine organic debris
							dark gray shale
5672					shale	normal offshore lacustrine	XRD greenish-gray silty shale with scattered fine organic debris
5673			FX		fine sandstone		horizontally laminated ss with abundant fine organic debris, fracture at 45°
5674			FX?		disrupted shale	slump	greenish-gray silty shale dipping 80° to subvertical subhorizontal but disturbed laminations with flat organic clasts [shale is rubble]
5675					shale	normal offshore lacustrine	light gray (slightly calcareous) shale, breaks conchoidally [shale is rubble]
5676					muddy ss with clasts	grain-debris flow	light gray clayey sandstone, much organic debris, some large (8cm) laminated shale clasts- all inclined 45°
5677			BTM OF CORE				

Lomax Exploration Co.

Lower Douglas Creek Sandstone Well 2-33 Travis Unit, Greater Monument Butte field Sample No.	Quartz	Plagioclase	K- Feldspar	Siderite	Calcite	Dolomite	Pyrite	Chlorite	Mixed-layer Chlor-smectite	Illite+ Mica	Mixed-layer ~~illite-smectite~~	Smectite	Amorphous/ Below Detect	% smectite in illite-smectite
5648 core Bulk	36	15	12		2	8	1	2	tr	4	20		-	
Clay								13	4	10	73			15
5650.5 core Bulk	43	14	5	2	20	5		4	tr	2	5		-	
Clay								7	9	14	69	1		15
5656 core Bulk	43	19	6	tr	20	3		2		1	5		-	
5659 core Bulk	40	17	6	tr	3	5	tr	4		5	19		-	
5666 core Bulk	42	17	8	1	7	7	tr	3		2	13		-	
5668 core Bulk	20	9	4	2	3	3		2		4	53		-	15
5672 core Bulk	16	6	5		4	3	3	2		3	58		-	15

Mineralology, Approx. Wt.% [X] (or) Relative Abundance [ ]

MM = Predominant M = Major m = Minor Tr = Trace ? = Tentative Identification

SUMMARY OF X-RAY DIFFRACTION ANALYSIS

UNIVERSITY OF UTAH RESEARCH INSTITUTE, EARTH SCIENCE LABORATORY

S. Lutz
revised
3-3-95

APPENDIX C - Detailed lithologic log of core and X-ray diffraction analyses from Travis Federal #6-33.

2

Well: #6-33 Monument Butte Interval: Top 5596-5602

Depth (ft)	Dominant Grain Size (Clay, Mud, Slt, VFS, FS, MS, CS)	Burrows (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
			TOP OF CORE				
5596			FXS?		organic-rich silty shale		XRD 5596.3-5597.0: rubble in shale- possibly fractured
5597							dark gray
5598			FX				
5599			FX FX			normal off shore lacus trine	slightly siltier shale, some faint deformed mottles, planar fractures with slickensides on shale, fractures dip about 45°
5600			FX		organic-rich shale		
			FX		bentonitic shale		medium gray bentonitic shale, top is burrowed gradational into organic shale, base is sharp; parallel, vertical fractures are coated with dead oil
5601					organic-rich shale		XRD
5602					shale		slightly lighter (bentonitic) shale, grades into overlying organic shale

Well: #6-33 Monument Butte Interval: 5602-5610

Depth (ft)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5602 – 5604			organic-rich shale	normal off shore lacus trine	a few lighter (silty) mottles dark gray shale with abundant flat organic debris
5604 – 5605			burrowed organic-rich shale		slightly compacted <u>Planolites</u> in organic-rich shale XRD
5605	FX FX		bentonitic shale		T.S. + XRD: light to medium gray shale with expandible clay, disrupted fabric, sharp upper and lower contacts are fractures, dipping at 45°
5606 – 5609	FXS?	py?	organic-rich shale		rubble in shale XRD lighter silty lamination dipping abut 30° dark gray organic-rich shale with subhorizontal flat organic debris
5610			disrupted silty shale	slump	one 4 cm thick medium gray silty lamination dipping 30° smeared fabric, gradational upper contact

Column headings also printed: Dominant Grain Size (Clay, Mud, Slt, VFS, FS, MS, CS); Burrows (W, M, S).

Well: #6-33 Monument Butte Interval: 5610-5617 Btm

Depth (ft)	Dominant Grain Size (Clay, Mud, Silt, VFS, FS, MS, CS)	Oil Stain (W, M, S)	Lithology	Sedimentary Structures	Facies	Depositional Environment	Description
5610					disrupted silty shale	slump?	mostly shale with some faint deformed mottles of silty material, gradational lower contact
5611					organic-rich shale	normal off shore lacus trine	dark gray shale, a few silty mottles at the top
5612				Py	disrupted mudstone		medium gray shale with silty mottles, possibly smeared burrows, subhorizontal
					bentonitic shale		medium gray shale with expandible clay, sharp upper and lower contacts
5613				Py	organic-rich shale		XRD dark gray shale, flat organic debris is horizontally oriented, gradational base
5614					disrupted silty mudstone	slump	
5615			FXS?		disrupted shale		dark gray waxy shale with a few silty mottles, dipping 30°, slumped nodular texture; 5615.1- 5615.5 rubble in shale, green material on rubble pieces
5616					burrowed organic-rich shale	normal off shore lacus trine	dark gray, organic-rich shale, possibly some burrows, a few silty mottles at the top
5617			BTM OF CORE				

Lomax Exploration Co.

Lower Douglas Creek Well 6-33 Core Travis Unit, Greater Monument Butte field **Sample No.**		Quartz	Plagioclase	K- Feldspar	Siderite	Calcite	Dolomite	Ferroan Dolomite	Pyrite		Chlorite	Mixed-layer Chlor-smectite	Illite+ Mica	Mixed-layer Illite-smectite		Amorphous/ Below Detect					% smectite in illite-smectite	
5596 Bulk		15	6	4			13		5		tr	2	3	52		-					~20	
5601 Bulk		30	11	4				5	3		3	1	5	38		-						
5604.5 Bulk		26	9	5			5		4		1	tr	2	48		-						
5605 Bulk		29	12	7			4	2	1		2	tr	3	40		-						
5606 Bulk		16	9	4	2		8		2		1		1	48		9						
5613 Bulk		23	12	5			4		12		2	2	4	36		-						

Mineralogy, Approx. Wt.% [X] (or) Relative Abundance [ ]

MM = Predominant M = Major m = Minor Tr = Trace ? = Tentative Identification

SUMMARY OF X-RAY DIFFRACTION ANALYSIS

UNIVERSITY OF UTAH RESEARCH INSTITUTE, EARTH SCIENCE LABORATORY

S. Lutz
revised
3-3-95